

UNITED STATES OF AMERICA
ELECTRIC ENERGY MARKET COMPETITION
INTERAGENCY TASK FORCE
AND THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Energy Market Competition Task Force

Docket No. AD05-17-000

COMMENTS OF THE PPL COMPANIES ON
WHOLESALE AND RETAIL ELECTRICITY COMPETITION

The PPL Companies¹ (“PPL”) appreciate the opportunity to submit these comments in response to the Electric Energy Market Competition Task Force's study of competition in wholesale and retail markets for electricity in accord with Section 1815 of the Energy Policy Act of 2005. PPL owns both transmission assets located within the PJM Interconnection, L.L.C. (“PJM”) and approximately 12,000 megawatts of merchant generation located within PJM, the New York Independent System Operator, ISO New England, and the Western Electricity Coordinating Council.

I. EXECUTIVE SUMMARY

PPL has been, and remains, a strong proponent of competitive wholesale and retail electricity markets. Under a competitive wholesale framework, the risks associated with investments in new generation are borne by generation companies' shareholders, rather than by ratepayers, as was the case under a regulated model. To

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encourage investment in new generation, however, the market must be permitted to send the appropriate price signals.

Over the long-term, wholesale and retail competition will result in lower prices than would have resulted under regulation. The benefits of competition to end-use customers have been evident in wholesale supply, where earlier over-building of generation has resulted in market prices approaching short-run marginal costs. Also, competition in the generation sector has resulted in operating efficiencies and higher availabilities and output from existing power plants, thus helping to lower production costs on a per-megawatt basis. Although competition has not resulted in myriads of suppliers competing for small customers, it can be argued that the prices paid are considerably lower than what they would have been under regulation. One recent study conducted by Cambridge Energy Research Associates (“CERA”) entitled, “Beyond the Crossroads: The Future Direction of Power Industry Restructuring,” has estimated that consumers paid approximately \$34 billion less for electricity over the past seven years than would have been the case under traditional regulation.

Unfortunately, a combination of nationwide and regional events has led to a retreat from free-market policies that hold significant promise for electricity users and investors alike. The introduction of market price mitigation measures threatens not only the operation of wholesale and retail markets, but also the adequacy and reliability of the nation’s electricity supply. Such artificial limits disrupt the normal functioning of the forces of supply and demand and have resulted in suppliers’ canceling plans to build new plants due to a fear of inadequate capital recovery. Wherever workably competitive markets exist, policymakers should reject measures designed to depress

price below market levels and other measures that impede the ability to markets to send proper price signals, even during conditions of scarcity.

II. OVERVIEW

A. Wholesale Electricity Competition

In its Notice, the Task Force comments that it is focused on the current state of competition and factors that help support or limit competition in wholesale and retail markets. Before addressing the Task Force's questions, a brief review of the history behind the transition to a competitive marketplace provides important background to the discussion of the current state of the industry.

Prior to restructuring, the electricity industry was seen as a natural monopoly. Electric utilities were primarily vertically integrated companies, incorporating generation, transmission and distribution functions. The industry operated under the concept of "regulatory compact" – *i.e.*, in exchange for the electric utility's promise to deliver electricity reliably and to build prudent facilities to fulfill that promise, the utility would recover its operating expenses and its investment costs, plus a reasonable return, in rates. The downside of this model was that utilities had limited incentive to control costs and operate efficiently and, in fact, had an incentive to grow their rate base, to earn higher overall returns.

The 1970s and 1980s saw a period of over-construction of capital-intensive base load facilities. High inflation and heightened regulatory requirements, particularly for nuclear generation, substantially increased the cost of these facilities and the associated financing. Growth in electricity demand did not materialize; and, as this expensive supply entered the market, average bundled retail electricity prices soared.

Regulators deemed significant amounts of the new generation to be “excess.”

Moreover, cost-based rates resulted in large rate disparities between utilities that were close geographic neighbors, which could not be justified other than on a historical cost basis. Consumers became increasingly aware of these disparities, which served as an additional driver for competitive markets.

Early Stages of Wholesale Competition

In the 1980s, the industry was already experiencing wholesale competition to some degree, through the Public Utility Regulatory Policies Act of 1978 (“PURPA”) and rather limited bilateral wholesale contracts between utilities. Wholesale competition gained momentum with the enactment of the Energy Policy Act of 1992 and was later further advanced by the issuance of Order Nos. 888 and 2000 by the Federal Energy Regulatory Commission (“FERC” or “Commission”). Policymakers recognized that, if the transmission grid were opened, competition in wholesale generation could work to control costs, eliminate disparities and lead to economically efficient decisions in new construction. Opening the grid caused an explosion in wholesale competition and in construction of new generation.

Regulatory oversight concentrated on market structure, *i.e.*, eliminating barriers to entry through open access transmission and the encouragement of Independent System Operators (“ISOs”) and later Regional Transmission Organizations (“RTOs”), preventing market concentration through merger review, and attempting to prohibit discrimination through mandatory equal access to the transmission grid and through affiliate codes of conduct. During this initial period of deregulation, the FERC relied principally on markets to address price spikes or other problems caused by

supply-demand imbalances. Only when there was a finding of a flawed market, a market that was not demonstrably workably competitive, or clear evidence of market power, was the Commission willing to consider intervention and price mitigation.

Wholesale Competition in the Last Five Years

With the advent of the California energy crisis and the demise of Enron, policymakers understandably began to rethink their approach to restructuring the electricity industry. Under intense political pressure to “do something” to shield ratepayers from high prices, the Commission instituted price caps much lower than the \$1,000/MWh protective caps upon which it had previously relied and suggested other steps that marked a retreat from market-based solutions, such as imposing must-offer obligations and requiring suppliers that had previously sold electricity into California to refund a portion of their profits. Some of these proposed measures were geared, not at market structure, but at controlling market outcomes. The Commission’s actions in California were followed by a series of additional moves that greatly reduced market liquidity and investor confidence, including:

- The Commission’s Market-Based Rate Conditioning Order, in which the Commission initially proposed to impose retroactive refund responsibility for vaguely-defined “anticompetitive behavior,” including selling at a price above the “market price” and the seller’s “full incremental costs,” which the Commission characterized as “economic withholding.”
- The new Supply Margin Assessment test and its successor, the Market Based Rate Pivotal Supplier and Market Share Screening Tests. These tests (still not final) determine whether market-based rates are appropriate.
- The Commission’s actions in consideration of complaints filed by the California Public Utilities Commission, the California Electricity Oversight Board, Nevada Power Company, Snohomish Public Utility District, Southern California Water Authority and others, seeking to abrogate long-term contractual commitments, many of which were the

basis for tens of millions of dollars of new investment in power plants by market sellers.

- The Commission's failed attempt at establishing a Standard Market Design, for consistent use across regions.

At the same time, the FERC also began to approve and support a series of measures in ISO/RTO markets such as soft price caps, automatic mitigation procedures, actions by market monitors to depress prices below market levels and other actions that impeded the market's ability to send proper price signals, especially during periods of scarcity. These measures are at the source of many of the problems that policymakers are grappling with today, such as resource adequacy mechanisms, locational capacity payments, attempted re-regulation of generation plants and inadequate generator revenues in RTOs like New York, New England and PJM.

The Current State of Competition

When the FERC began imposing price caps, market mitigation measures and retreating from markets, suppliers' previous optimism about the future of the competitive marketplace dissipated. Generating companies became increasingly aware that their investment returns were not being driven by the forces of supply and demand. Rather, these returns were at the mercy of threatened and actual intervention into the market.

Price caps and other mitigation measures pose a critical obstacle for potential investors in new generation. The forces of supply and demand drive prices toward average variable or even marginal cost. Although suppliers can stay in business in the short-term by at least recovering their marginal costs, they must be able to recover a return both on and of their capital investment at some point. Without this, over the long-term, suppliers in any industry will be forced out of business and no

investor would be willing to put new capital at risk. In the wholesale energy supply industry, the occurrence of “peak” prices, which occur during infrequent periods when demand unexpectedly outstrips supply, presents this opportunity for investors to recover some portion of their capital costs. These periods are exceptionally rare; for example, since the beginning of 2000, spot market prices for energy at the PJM Western Hub have exceeded \$250/MWh less than 1/10th of 1% of the time. Yet it is absolutely essential that suppliers be permitted to charge the prevailing market price during these rare occasions. Only in this way will new capital be attracted to the industry to support construction of new competitive generation in the future.

The Commission’s policies, combined with the general downturn in the economy, essentially froze generating companies’ willingness and ability to build generation and market electricity nationwide. For instance, of the 138,000 MW of interconnection requests submitted to PJM since 1999, approximately 106,000 MW have been withdrawn. As long as regulatory impediments to the functioning of a competitive marketplace continue, construction of new, large-scale, base load competitive generation simply will not occur.

If Congress and the FERC had only sought greater efficiencies in generation dispatch and coordinated grid operation, these goals could have been achieved under the regime of central resource planning and security-constrained economic dispatch of generation in a geographic region. This is exactly what was occurring in PJM prior to the advent of electric competition. But the promise of wholesale electricity competition was, and still is, far greater. Real competition in wholesale generation is intended to bring the lowest, long-term prices for wholesale

generation supplies, cause capital to be allocated efficiently by placing the right type of new generation in the right place, increase adequacy (and reliability) of generation supplies, and prevent wholesale and retail customers from bearing significant risks associated with constructing generation. These are the true benefits of competitive wholesale markets, which exceed the benefits derived from short-term marginal cost dispatch of existing generation.

Although more benefits remain to be realized, some have already been seen. As a result of competition, the generation industry has become much more efficient; existing facilities are now more productive. For example, the average equivalent availability of PPL's PJM coal plants increased from 78.6% in 1992-94 to 87.3% in 2002-04, and the related statistics for PPL's Susquehanna nuclear facility improved from 76.5% to 89.7% over the same period. Increased production puts downward pressure on prevailing market prices for energy and also results in less need for siting new generation and transmission facilities, which, in turn, is beneficial for the environment. Moreover, increased production from existing facilities lowers the average total cost of energy per MWh, which benefits investors, because it translates into the opportunity to earn greater returns on already-sunken capital.

What should policymakers do today? Policymakers should recommit themselves to allowing market forces to send proper price signals for generation and state their intent to reject or end measures that interfere with or prevent appropriate market price signals. Policymakers should permit and encourage reliance on market forces to establish prices in all workably competitive markets – even during conditions of scarcity. At the same time, policymakers must act strongly to prevent market abuses.

Policymakers also may have no choice but to employ some cost-of-service regulation in areas without competitive options. But beyond those narrow roles, policymakers should act to promote aggressively true market price signals, including scarcity pricing. Scarcity pricing is essential to permit capital cost recovery and to send the right price signals to encourage new investment.

B. Other Critical Elements of Competitive Wholesale Markets

In addition to the commitment to allow market prices to be set by the forces of supply and demand, PPL believes there are several other elements essential for a well-functioning competitive electricity market:

- **Non-discriminatory transmission access.** Entry to the market is an essential first step in achieving the goal of competitively priced generation supply options.
- **Reliability and regional planning.** Reliability remains a key underpinning of electricity markets. Responsibility for transmission reliability investments and for recovery of those investments should ideally be established through an RTO. Regional planning is essential so that the right solution is designed taking long-term planning into account.
- **Existence of both energy and capacity markets.** Both energy and capacity markets may be needed when price caps (even a \$1,000/MWh price cap) remain, but a well-functioning capacity market with a forward component must exist to ensure that generators have an opportunity to recover their costs.
- **Bilateral contracts.** A well-functioning bilateral market with both short- and long-term contracts is essential to functional energy and capacity markets. Over reliance on short-term spot market transactions can lead to price spikes for customers, little new investment and potential reliability concerns.
- **Economic dispatch of generation.** The best available resource should be dispatched based on efficiency, taking into account price and non-price terms, including legitimate operational restraints. In a functional RTO such as PJM, economic dispatch necessarily occurs; in other regions, economic dispatch should be required.

- **Cost accountability for RTOs.** RTOs should be managed under corporate governance models well established in for-profit corporations. If an RTO incurs a liability or a penalty, under the present structure, it simply passes the costs along to its member companies. For-profit companies experience the associated financial consequences of their errors and are governed by a fiduciary responsibility to their owners for their behavior. The management model for RTOs must include a similar mechanism for corporate responsibility and accountability. Without effective cost controls and enhanced accountability, RTOs may be unable to meet future challenges.

One solution will not fit all markets or regions. But when the forces of supply and demand are allowed to work unimpeded, over the long-term, competitive markets will offer consumers lower prices than would have been the case under a regulated market, due to greater efficiency from the use of the most economic generation and transmission resources. The success of one or more regional competitive markets may well help other regions without competitive markets take the next step.

C. Retail Electricity Competition

Without Federal legislation mandating competition in retail electricity, retail competition has varied widely state-to-state. But even in states where there has been movement toward retail competition, it has been necessary to accommodate transition periods during which “stranded” costs are recovered from retail customers. During these transitional periods, fixed rates, at or below market, available to provider-of-last-resort customers have effectively curtailed most retail competition. This has been the experience in Pennsylvania, for instance.

As states with retail competition rules exit from transition periods, one lesson seems to be emerging. If states decide that customers will be exposed to market prices, a robust market for retail choice will emerge, with creative options, products and services. In New Jersey, for example, this has proven to be the case. If, on the other hand, customers are permitted to retain the option to fall back on supply under a provider-of-last-resort option, then retail shopping will be substantially less, as competitive suppliers find themselves competing with the provider of last resort, often the local electric distribution company.

D. Other Critical Elements of Competitive Retail Markets

As a base for the development of competitive retail markets, a workable and well-functioning wholesale electricity market in the region is required, to make supply available to potential retail suppliers. Also, education of retail customers as to their choices and benefits provided is key; and most states that have instituted retail choice programs have recognized this and taken steps to address it. Deregulation of retail markets should best occur in stages to facilitate the education process.

For consumers to have greater information and control over their choices, real-time price signals should be encouraged. As shown by the success of demand-side management programs in states such as California, consumers can understand that electricity usage during certain high-cost hours may be negated during off-peak hours and can take steps to modify their consumption accordingly. If real-time price signals become more widely available over time, retail customers could take a more direct and active role in tailoring their electricity consumption in response to hourly, or more real-time, prices.

III. WHOLESALE MARKET RESPONSES

While PPL's following comments and responses are focused primarily on the PJM RTO, most also have applicability to design of markets throughout the nation.

A. Wholesale Supply Trading and Participation

1. To what extent does wholesale trading help result in an economic and reliable supply of electricity in each region? What are ways to improve the provision of an economic and reliable supply of electricity?

Wholesale trading helps to ensure an economic supply of electricity by promoting liquid, competitive markets. It improves price convergence between contiguous regions. It provides an effective tool for risk management. Wholesale trading also promotes reliable supply by sending the appropriate price signals to encourage investment and conservation, when and where needed.

2. What share of electric power used to serve retail (or ultimate consumer) load is obtained through wholesale market transactions in each state or region? In what ways has this share changed over the past 10 years and the past 5 years and why?

Prior to deregulation in PJM, almost all power transacted in the PJM interchange was via the (spot) market. The amount of supply obtained through wholesale market transactions has increased steadily since then. Based on available data from PJM's State of the Market Report, one way to answer this question is to analyze spot market volume vs. load. PJM reports that spot market volume is about 50 percent, so physically scheduled bilateral transactions would be about 50 percent. The 50 percent physical bilateral transactions do not include financial bilateral transactions, which would be part of spot market volume. So the actual volume of wholesale transactions is likely in excess of 50 percent.

3. What share of electric power used to serve ultimate consumer load is generated by a utility for its own native load? What share of electric power used to serve utility customer load comes from utility affiliates? What share comes from unaffiliated generators?

PPL's energy marketing affiliate, PPL EnergyPlus, provides power supply under a long-term agreement to its electric distribution affiliate, PPL Electric Utilities. This power supply contract serves the portion of PPL Electric Utilities' ultimate consumer load for customers that have not chosen an alternate energy supplier under the Pennsylvania retail choice program. On an annual basis, more than 80 percent of the power used to serve this ultimate consumer load is produced by generation owned by PPL's generation affiliates and located within the PJM-RTO.

4. What opportunities exist for generation owners to sell output in wholesale markets?

PJM and other RTO/ISOs have established energy, capacity, and ancillary services markets where generation owners can sell (and wholesale power buyers can purchase) their output. In addition to these clearing markets, these products are traded bilaterally via brokers, exchanges or directly between counterparties.

5. What opportunities exist for wholesale power buyers to purchase electricity in wholesale markets? Is demand (negawatts) a product that can be traded in the wholesale market?

See answer to question 4. Also, suppliers of negawatts can participate in emergency and economic load response programs that have been established by RTO/ISOs and load-serving entities. As an example, PJM has proposed a Forward Energy Reserve product that would allow providers of negawatts to sell them on a forward basis. However, demand response programs have typically been heavily subsidized by either RTO/ISOs or load-serving entities to make them cost effective.

Nonetheless, PPL believes that demand response is an important part of competitive wholesale markets. To further enhance demand response, customers must be aware of the real-time price of electricity. When faced with the real-time price signals, customers then can make choices on whether or not to consume the next increment of energy.

6. Is there an organized regional market or exchange serving buyers and sellers in the region? What products does the organized market provide? What percentage of energy supplied is secured through organized markets and through bilateral trades? Are there liquid trading points in the region? What are the volumes traded? What is the trend of bid/ask spreads (getting greater or smaller)?

Yes, within PJM, there are spot markets for energy, capacity, and ancillary services. See answer to Question 2 for spot market vs. bilateral trade volumes. PJM has the Western Hub as its most liquid trading point. PPL is also an active member in the New England and New York power markets. These markets actively trade similar products as found in PJM.

Generation owned by PPL in the western United States participates in bilaterally traded markets in the Pacific Northwest and desert Southwest. Liquid trading points exist within these regions as well.

7. To what extent do wholesale buyers and sellers participate in futures or other commodity markets or transactions to balance the financial risks of competitive electricity markets? How liquid are forward markets in different regions and how far ahead can one transact in these markets?

PJM's forward energy markets are reasonably liquid, and transactions can be made through brokers or exchanges 5 to 6 years in the future.

8. What role have credit issues played in the ability of market participants to participate in wholesale markets, including forward markets?

Credit issues can limit the ability of smaller or poorly rated market participants to participate in wholesale markets.

It is also clear that the credit rating agencies have had a significant influence in assessing the risk of participating in wholesale markets. Business risk profiles of companies actively engaged in wholesale markets are typically higher. In addition, the credit rating agencies have taken a negative view toward purchasers entering into long-term contracts. These long-term contracts are typically treated as imputed debt obligations, even if recovery of purchase power costs are approved by regulators. At the same time, these credit rating agencies take a dim view of companies that have significant unhedged positions, by potentially downgrading their credit quality.

Further development of credit clearinghouses for electric energy markets could improve liquidity and enhance bilateral trading by lowering collateral requirements. PPL would encourage exploration of the development of such entities within RTO/ISOs markets.

9. Are there competitive processes by which distribution utilities solicit proposals for native load or default service?

In PJM currently, there is the New Jersey Basic Generation Service (NJ BGS) auction, and in Maryland, the Standard Offer Service (SOS). Other states in the region like Ohio, Connecticut, and Massachusetts have also used competitive procurement processes to solicit default supply for native load customers.

10. How can changes and trends in wholesale market prices by region be measured?

PPL has no specific comment.

11. How should the performance of wholesale markets in serving the needs of various types of power sellers (e.g., marketer, generator, independent producer, merchant, public utility, nonpublic utility, qualified facility, renewable power producer, co-generator) be measured?

In measuring the performance of wholesale markets, one might ask the following questions:

- Are they competitive?
- Are there well-established rules that are applied consistently?

- Are they liquid enough, and do they go out far enough in time to provide a good hedging mechanism?
- Do they send the proper price signals to encourage the appropriate behavior (e.g., investment in generation or demand response)?

12. How has restructuring of incumbent utility operations and the introduction of competitive retail markets in retail choice states affected participation in regional wholesale markets? Has the introduction of retail markets affected the level of long-term contracting in wholesale markets?

In Pennsylvania, a retail choice state, rate caps and transition periods were required because of the need for recovery of stranded costs, thus participation in regional wholesale markets has not been impacted greatly. Once transition periods expire and retail rate caps are lifted, this may change.

13. Please describe instances in which competition has resulted in relatively higher prices or lower reliability in a specific regional market.

The most well-known and most widespread example of the results of implementing a flawed deregulation plan was California which significantly contributed to the energy crisis in 2000-2001 and the dramatic price volatility that ensued. The major flaw was not establishing a capacity obligation and associated market along with the long-term bilateral energy market; as a result, in the years leading up to the crisis, wholesale power prices were too low to provide the economic signal for new supply to be built in California.

B. Generation Ownership

PPL has no specific comment to the questions in this section.

C. Generation Adequacy

1. How is generation adequacy addressed in each region or system? Is there a specific enforceable requirement that load serving entities or market participants must meet? How is planning for generation adequacy conducted?

In PJM, load-serving entities must meet their obligations to provide capacity based on the established "Installed Reserve Margin." PJM does not perform any additional planning for generation adequacy.

2. Has new generation construction kept pace with demand growth in the state or market region? If not, why not? What are the most important factors that affect whether generation will be built?

In PJM, generation has kept pace with demand due to earlier construction, but revenue adequacy currently is a problem. A stable set of rules needs to exist

that will provide a predictable revenue stream and hence the expectation of recovery for all costs with the opportunity to earn a reasonable return.

3. What role does the ability to enter into long-term contracts play in financing new generation projects?

The ability to enter into long-term contracts is very important, if not critical, given the need to recover generation investment over a significant number of years. While PJM has built up a very high reserve margin, recent experience with revenue inadequacy in PJM will make it difficult to finance projects without cost recovery mechanisms such as long-term contracts. Credit issues associated with long-term contracts are also very important if new generation is to be financed. As indicated above, the credit rating agencies have significant influence on how a long-term contract is viewed on a purchaser's balance sheet. By imputing a certain debt component to a long-term contract, it can distort the economic advantages of contracting for power. In most instances state regulators approve the recovery of competitively bid purchased power costs, which should remove uncertainty the rating agencies have with long-term contracting. Continued uncertainty in how purchased power will be treated by the credit rating agencies only leads to fewer projects being developed in the competitive wholesale market.

4. What generation facilities have been installed in the past five years? What was the experience in the process?

PJM received approximately 138,000 MW of interconnection requests from generators since 1999. Of those 140,000 MW of requests, approximately 106,000 MW were withdrawn. Approximately 16,000 MW of new generation was built and about 16,000 MW of requests remain active.

5. What generation facilities have been cancelled in the past five years and why?

See answer to question 4. Those projects that were cancelled were likely due to the current revenue inadequacy in PJM markets. According to the PJM Market Monitor, net revenue from PJM markets has averaged below the level of full cost recovery for new peaking generation for the period 1999-2004.

6. What difficulties, if any, have developers of new generation facilities encountered in bringing generation supply to market? (E.g., difficulties in financing, siting, permitting, licensing, interconnection, transmission access, fuel supply). What are ways to improve the process?

In PJM, developers have encountered changes in market rules and reserve requirements that have created uncertainty in revenue adequacy and future cost recovery. One important improvement would be a stable set of resource adequacy market rules that would encourage short-term and long-term bilateral

contracting. Another recommendation would be to provide the market with better information about future supply and demand conditions, and potential transmission constraints. As explained in response to question 3 above, credit issues are also important.

7. Are there instances in the past five years in which a new generation facility has been completed that caused prices in a previously congested area to decline?

PPL has no specific comment.

8. How do the approaches and responsibilities for assuring the availability of sufficient generation capacity to meet peak load and load growth vary among regions and states that have retail choice and/or tightly organized regional markets and those that do not?

CERA has provided a complete summary in their special report "Beyond the Crossroads, The Future Direction of Power Industry Restructuring." Their key recommendations related to resource adequacy are:

1. **Act now.** There is a shrinking window of opportunity that exists before new resources need to be in place.
2. **Implement a policy that has a high probability of success.** Ensure that the right capacity gets built when and where it is needed.
3. **Provide clarity and certainty in the rules.** There should be clear responsibility and clear rules.
4. **Coordinate rules.** Resource adequacy rules need to be coordinated with other market rules so they don't undermine the overall operation of the competitive markets.

There are many varied approaches being used or proposed in the regions and states. CERA summarizes and evaluates nine approaches to dealing with resource adequacy and evaluates each one based on six criteria. They have concluded that none of the mechanisms is perfect.

CERA also concluded that several of the mechanisms should not be pursued because they have a low probability of success. PPL believes that several of the other mechanisms studied may produce a reliable power system but have a decentralized approach that does not allow competition to provide the best price or technology choices for development of future electric supplies. Thus, these options may not result in the most cost-effective, innovative or economically efficient choices and fail to consider alternatives such as new transmission or demand-side options.

Of the remaining options examined by CERA, PPL believes that the option requiring regional RTO capacity markets -- locational in nature with a downward sloping demand curve -- would seem to provide an attractive choice for restructured markets and may have a high probability of success. If implemented

correctly, so that bilateral markets can operate within this environment, this approach appears to address many of the key criteria for meeting future resource adequacy needs, such as assigning clear responsibility establishing stable pricing signals to encourage sufficient long-term commitments for new generation, encouraging bilateral capacity contracts with the discipline offered by price transparency in the auctions, encouraging prices that reflect the cost of new entry and assure generators of being able to cover the cost of financing through a stable revenue stream, encouraging better siting through the use of locational market price signals, and finally, providing clear pricing for the value of transmission projects and demand side resources.

9. What incentives do competitive suppliers have to maintain adequate reserve capacity?

Well-designed capacity markets can provide an incentive for suppliers to build sufficient generation to maintain reserves. Obligations imposed on load-serving entities by the RTO/ISO or state regulators create the demand for adequate reserves.

10. What incentives or responsibilities do load-serving utilities have to maintain adequate reserve capacity?

Their incentives are obligations imposed on them by the RTO or their state regulator.

11. How can competitive markets assure adequacy of generation supply? How is reserve sharing to meet state or regional generation adequacy standards accomplished in competitive markets? How can other institutions/market processes provide an effective substitute for reserve sharing?

A well-designed capacity market is a competitive market mechanism to assure adequacy of generation supply. For instance, PJM's proposed Reliability Pricing Model (RPM) is not well-designed and will not result in construction of new capacity. PJM expects RPM will encourage generation investment by providing one-year of guaranteed capacity revenues four years in the future and the opportunity for additional one-year guarantees of capacity revenue in subsequent years. To the contrary, PPL believes that RPM will discourage investment in new resources. RPM's one-year capacity revenue stream four years out will not convince any new investors to commit capital to PJM. New generation investment in PJM will be forthcoming only if investors can secure stable, compensatory, long-term revenue streams. And stable, compensatory, long-term revenue streams will come only from long-term capacity contracts that result from a well-designed robust, functioning bilateral market.

PPL believes investment in new generation only will occur when investors conclude that market rules - including mitigation, scarcity and resource adequacy measures - provide investors a reasonable assurance of capital cost recovery.

Instead of adopting the flawed RPM model, PJM should make the following incremental modifications to the existing capacity model.

- Eliminate the daily markets and replace them with monthly or annual markets;
- Include a location capacity component;
- Impose a rational downward sloping demand curve that will ensure generators can recover their fixed costs, promote reliability, and address market power concerns;
- Establish a forward obligation for capacity;
- Require PJM to share relevant planning information with the market;
- Impose on loads an obligation to certify any unhedged capacity positions;
- Hold a back-stop capacity auction no earlier than one year prior to the Delivery Year to meet any unmet needs; and
- Most importantly, these steps will promote long-term and short-term bilateral contracting as the real solution to the problem. This is the solution that is truly needed to resolve capacity issues in PJM today.

D. Transmission Investment And Regulation

1. What are the most important factors that affect whether transmission will be built? What are ways to improve the process? What difficulties have transmission owners had in upgrading or building new transmission facilities? What are the prospects for merchant transmission?

The most important factors that affect whether transmission will be built are the application of a regional transmission planning process administered by an independent transmission system administrator, the assurance of reasonable return on investment, the assurance of complete and timely cost recovery and federal siting/ eminent domain backstop authority. EPCRA has addressed the investment and cost recovery requirements as well as the backstop siting/ eminent domain authority. What remains is for the PJM RTO to expeditiously identify needed new transmission in the Regional Transmission Expansion Program ("RTEP") so that it can be built by the applicable transmission owners. There are prospects for merchant transmission given the significant amount of congestion within the PJM region as well as elsewhere in

the country. The PJM model provides for the development of merchant transmission. However, available cost recovery mechanisms remain elusive for most merchant transmission projects. An exception is the Neptune Project, which is a DC link between PJM and NYISO. Here, cost recovery is accomplished by selling reservations for power that can be scheduled across the DC line.

2. Over the past 10 years, what have been the trends in investments in transmission by utilities by state or region? Are there any prevailing patterns in transmission investments in upgrades and replacement of existing plant versus new lines, interconnections, automation? Have these patterns of investment shifted over this period? Are there any projected changes in patterns of transmission investment over the next 5 years?

For the PJM region, there has been significant transmission development. Much of the transmission development has been associated with interconnecting new generation to the PJM system. However, a significant amount of new transmission for assuring system reliability has been identified in the PJM RTEP and has been built or is under construction. All projects identified in the PJM RTEP are committed to be built by the applicable transmission owners in PJM. For the future development of the transmission system, the PJM RTO has been asked by the stakeholders to provide long term transmission plans (10 or so years) to both assure system reliability and to improve market efficiency. A stakeholder process is underway to develop the procedures to assure the provision of such long-term plans.

3. How are transmission needs of merchant generators and renewable energy projects included in regional or utility transmission planning and upgrades?

Such projects are accommodated in the generation interconnection process administered by the PJM RTO consistent with Part IV of the PJM tariff.

4. How has the establishment of Regional Transmission Organizations (RTOs) changed transmission operations, transmission planning, and investment patterns?

RTOs have favorably affected the development of both intra- and inter-regional transmission planning. Transmission development under the RTO model is coordinated and more cost effective than if companies continued to develop their systems in isolation from neighboring systems. Coordinated operations have resulted in significant economies that would not otherwise have been available in a stand-alone -- or even a power pool -- structure. However, there is a significant challenge in developing long term transmission plans in that long term generation development is subject to market forces -- and therefore, unknown -- resulting in immature and not yet fully accepted procedures for projecting generation dispatch for 10 or so years into the future.

5. Within a region or RTO, is there a different process for transmission upgrades that are not required for reliability but would increase access to lower priced power in areas with economic congestion?

The PJM RTEP provides for both reliability upgrades as well as for economic efficiency (market efficiency) enhancements. One process covers both categories of transmission requirements.

6. In the absence of RTOs, how is transmission planning, siting, and construction for regional needs coordinated among utilities, generators, and State regulators? What challenges do transmission owners face upgrading or building new transmission facilities?

Transmission planning should take into account the efficient utilization of existing resources, planned generation additions that intend to offer their output to network customers and native load, and support for transmission services that involve both intra- and inter-regional transfers of power to other systems. Transmission customers must have a meaningful role in the development of the regional plan, and preferably an independent organization should oversee the process, including the development of base plans, the performance of studies, and any procurement solutions associated with resolving system constraints. Transmission expansion costs that are reflected in the regional plan and that support network customers' use of existing and future resources should be supported by network service rates.

7. How have transmission costs changed for transmission owners and for transmission customers over the past 10 years? What are the reasons for any increases or decreases?

Transmission costs for transmission owners have been increasing steadily over the last few years resulting in several transmission owners filing for rate relief at the FERC. Given that there are significant new transmission projects in the five year period identified in the PJM RTEP, other transmission owners will, in the near future, be filing for rate relief at the FERC. When PJM begins analysis of the 10 year forward system, it is expected that more work will be identified that will be required to be initiated within the next five years to meet anticipated reliability needs and market efficiency opportunities. The effect on transmission customers of the increased role of the transmission system to provide reliable delivery and lower cost energy has been a modest increase in transmission costs for most transmission customers. Much of the slightly higher cost to customers is due to costs of the PJM RTO administrative function and to the cost of ancillary services required to provide transmission service.

E. Wholesale Market Transparency And Information

1. Do purchasers and sellers view markets as providing stable, transparent prices? Are there differences among products and markets?

In RTOs/ISOs, there is good information on those products that are actively traded.

2. Is there sufficient timely and accurate publicly available information to assure that market participants can adequately assess the economics of proposed wholesale power transactions or assess the financial implications of self-build versus competitive alternatives for generation supply?

As stated above, there is good information on those products that are actively traded, for the terms they are traded. For example, there is liquidity in PJM energy out to about 5 or 6 years. To the extent this information would be useful in assessing the implications of self-build versus competitive alternatives, it is available. If a robust assessment of self-build versus competitive alternatives requires longer-term pricing, a robust assessment would be prevented more by lack of liquidity than a lack of good information.

3. How can any information deficits be remedied to improve the utility of market information? Are there any competitive risks associated with greater transparency of prices or of other information about market participants?

There can be competitive risks associated with providing information about the actual supply curve. Information about the supply curve, especially if it changes dramatically in a short period of time (e.g., due to an unexpected outage), can cause remaining suppliers to behave in a manner inconsistent with perfectly competitive outcomes. Therefore, certain details about pricing along the supply curve should remain confidential.

4. Are there open and transparent processes by which load-serving entities solicit proposals for generation from independent firms and/or from affiliated generators?

Yes; the NJ BGS auction, and the Maryland SOS.

IV. RETAIL MARKET QUESTIONS

A. Retail Markets Overview

1. What factors or measures should the Task Force examine in reviewing state retail choice experiences? How should these factors and measures be evaluated?

One obvious measure is prices, however; the true measure is not whether retail prices in competitive markets have gone up, down, or stayed the same or how

prices in states with retail competition compare to those in fully regulated states. Rather, have market efficiencies spurred by competition resulted in prices that are lower than they would be otherwise? This will be difficult to assess because it requires one to speculate what electric infrastructure would have been constructed, what regulatory treatment would have been granted, and what pricing would have resulted in the absence of competition. In addition, any analysis of pricing must recognize that, in the interest of consumer protection during the transition from regulation to competition, many jurisdictions capped rates at pre-transition levels and these capped rates will distort any efforts at comparisons either within the jurisdiction or across jurisdictions.

In addition to prices, the Task Force could examine the variety of retail electricity products offered, customer satisfaction, the number of customers taking competitive service and the number of suppliers offering competitive retail supply. However, in instances where the capped rates described above may have been more attractive than competitive rates (either because the price was lower, the terms were more favorable, or both), the number of competitive suppliers willing to serve customers, the number of customers taking competitive service, and the variety of retail products offered may all be artificially affected.

A more objective assessment that the Task Force could perform is an examination of the competitive market infrastructure in place in states that have moved to retail competition. The Task Force should examine whether the procedures in place are tested and operational to support a competitive market. These procedures should incorporate appropriate "switching" rules under which customers can select between competitive suppliers and Provider of Last Resort ("POLR") service. In addition, the procedures should incorporate comprehensive computer protocols to support interfaces between competitive suppliers and incumbent utilities. If all of these procedures are in place, the state retail choice program may support a vibrant, competitive market when/if artificial constraints are removed.

2. How should the Task Force assess the performance of evolving competitive retail markets?

See answer to Question No. 1, above.

3. How can the performance of competitive retail markets for retail customers be measured in the absence of competitive suppliers for residential and small business customers in many areas?

See answer to Question No. 1, above.

4. Why did your state implement a retail choice program?

Pennsylvania passed legislation in 1996 to implement a retail choice program in the Commonwealth through deregulation of the generation function. The legislation had broad support by all major stakeholders, including electric utilities, consumer groups, industrial customers, regulators, environmentalists and marketers. This restructuring of the electric utility industry was driven by perceived rate disparities among the electric utilities in Pennsylvania. It also was driven by perceived disparity between average electric rates in Pennsylvania and average electric rates in neighboring states. The proponents of the restructuring believed that competition among generators would benefit customers by reducing rates and increasing customers' options. In a competitive market, customers would be able to choose among different suppliers and various products. All stakeholders recognized that the distribution function should remain regulated by the Pennsylvania Public Utility Commission ("PPUC") and the transmission function should remain regulated by the FERC.

5. Why did your state decide not to implement a retail electric choice program?

Not applicable.

B. State Retail Choice Experience

1. How have customers benefited from retail electric competition? How have consumers been harmed by retail electric competition?

Pennsylvania's restructuring legislation established separate rate caps on distribution charges and on generation charges during the period that utilities collected stranded costs. Those caps provided a measure of price stability for retail customers. In the case of some utilities, the caps were extended by settlement for five years or more beyond the statutory requirement; thereby, providing additional price stability. Finally, in some instances, the capped rates included modest price reductions. Because capped rates were set for periods that were, in some cases longer than ten years, those rates have been above or below market prices from time to time. For those utilities where the price caps have expired, retail customers are provided default service at rates that reflect the cost to procure generation in the wholesale market at "prevailing market prices." PPL is not aware of any consumers who have been harmed by retail electric competition.

2. How have retail customer prices changed since the beginning of the transition to retail choice? Have the changes been comparable across all classes of customers?

See the answer to Question B.1, above. Capped rates for all customer classes reflected rates in place January 1, 1997. As rate caps end, rates can be revised as follows. Changes in delivery rates since that time have reflected updated cost of service studies and, therefore, reflect the cost to serve individual customer classes. Changes in generation rates reflect the cost to procure generation at

the wholesale level at market-based prices and losses associated with service at different end use voltages.

3. How many alternatives competitive retail suppliers are currently soliciting or accepting new customers in each service area? Has the number increased or decreased since the state introduced retail choice?

The PPUC maintains a website that lists competitive suppliers that are active in the service territories of each of the Commonwealth's electric utilities. That website can be found at

http://www.puc.state.pa.us/electric/electric_suppliers_list.aspx. The number of suppliers has generally decreased over time in service territories where rates have remained capped. PPL does not know whether the number of suppliers has increased or decreased in service territories where rates are no longer capped.

4. Does the availability of alternative suppliers differ among service areas, customer classes, load size, rural and urban areas, or other geographic areas, or by credit policies?

The website referenced in the answer to Question B.3, above, provides separate lists of competitive suppliers offering service to residential and non-residential classes of customers in each utility service territory. Those lists indicate that the availability of competitive suppliers varies among service territories and customer classes.

5. Have suppliers offered new types of products and services (e.g., time of day pricing, interruptible contracts, green power, etc.) in states where retail competition has been implemented? If so, describe the products and what customer response has been.

Competitive suppliers have marketed generation with environmental attributes to end use customers. Competitive suppliers have also marketed various forms of pricing and contracts including interruptible power. PPL does not have information on specific products and customer responses to those products.

6. How do retail customers obtain information about competitive alternatives? Do retail customers have enough information to readily make informed choices among competing suppliers?

In Pennsylvania, both the PPUC and the Office of Consumer Advocate maintain websites with information about competitive alternatives for retail customers. Each electric utility also maintains information (typically via website, mail, or phone) about competitive alternatives and the process for selecting a competitive supplier. Finally, each electric utility provides its retail customers information in May and October of each year on the price of its default service for the purpose of providing customers a basis for comparing competitive offers.

7. Does the state allow groups of retail customers to aggregate their electricity demand? How are they structured? What customer groups are included? Is participation on an opt-in or an opt-out basis? Has aggregation enabled customers to benefit from retail electricity competition? If not, why not?

Pennsylvania's competitive rules are designed to permit competitive supply on an account-by-account basis. Within those rules, competitive suppliers are free to serve whatever customers or classes of customers they choose in order to obtain marketing or supply advantages which they may or may not pass on to the customers they serve.

8. Now that many state-mandated transition periods to phase-in retail competition are ending, what issues do states face to ensure competitive retail markets?

Key issues being addressed in that process are (1) what entity provides default service, (2) how is default supply obtained in the wholesale market, and (3) how is it priced and under what terms and conditions is it provided to retail customers who are not served by a competitive supplier. In New Jersey, for instance, pricing of default supply service for commercial and industrial customers that exposes them to PJM market prices has caused significant levels of shopping for supply from competitive suppliers.

C. Retail Supply Questions in States with Retail Competition

1. How does the state program address assurance of adequate generation supplies for default service customers (i.e., customers that: (a) do not choose a competitive provider, or (b) have lost their competitive supplier for whatever reason)?

In Pennsylvania, the legislation requires the electric delivery company ("EDC") to be the provider of last resort for default service customers until the end of the transition period for the collection of stranded costs. PPL Electric Utilities has a long-term supply contract with its affiliate, PPL EnergyPlus, to supply the default service customers. The PPUC is currently in the process of developing the regulations governing the supply of default service customers after the transition periods end for the EDCs.

2. How do default service obligations affect retail power competition? Do the transmission services allowed for default service obligations affect retail competition and, if so, how? What changes, if any, would you suggest in these transmission services?

Default service obligations can affect retail power competition in several ways. First, the price of default service establishes a price against which retail customers can compare competitive options. Second, the terms and conditions under which default service is offered establish a basis for comparing pricing

variability, risk, and other non-price attributes of competitive alternatives. Finally, any switching rules associated with default service affect the ability and willingness of customers to seek out competitive alternatives.

The transmission service charged for default service by PPL Electric Utilities does not affect retail competition. PPL Electric Utilities' transmission service charge is a pass-through to the default service customers of costs incurred based on the FERC-approved transmission rate. Competitive suppliers are subject to the same FERC-approved as PPL Electric Utilities.

PPL does not suggest any changes in the transmission services for default service customers.

3. How has the development of RTOs affected the development of retail competition in the state?

The RTO for PPL's regulated distribution utility and for most of PPL's generation is PJM. Over the past several years, PJM has instituted a number of infrastructure changes that have benefited retail competition. PJM has refined its energy market and market settlement functions to accommodate retail competition. PJM has developed transmission and capacity tags and planning procedures that accommodate the movement of customers among load serving entities. PJM has developed information systems that support retail competition. And PJM has introduced new credit procedures that mitigate some of the financial risks associated with an influx of new market participants.

4. Did the state require that the incumbent utility divest all or some of its generation assets used to serve its retail native load when retail competition was introduced? Did incumbent utilities voluntarily divest generation assets as part of restructuring to implement retail competition? Did incumbent utilities transfer ownership of generation assets used to serve native load to an affiliated entity?

In Pennsylvania, the incumbent utility was not required to divest its generation assets, but some did. Others transferred ownership to affiliated entities. PPL Electric Utilities was not required to divest its generation assets when retail competition was introduced. The generation assets of PPL Electric Utilities were transferred to affiliated entities.

5. What has been the result of generation ownership transfers serving the state or region since the start of retail competition? Has there been a consolidation of generation ownership in the state or region?

New generation, and the transfer of ownership of some existing generation within Pennsylvania and within PJM, has served to increase the number of generation suppliers. The concentration of generation ownership, however, may be increasing due to mergers and acquisitions.

6. If a retail load-serving utility no longer owns sufficient generation assets to meet its obligations to its retail customers (existing customers, or as the supplier of last resort or default service provider) what mechanism (e.g., spot market purchases, buyback or output contracts, etc.) does it use to obtain generation services to fulfill these obligations? What share of a utility's load is obtained via the different mechanisms? How are these shares trending?

Through the transition, EDCs may meet their obligation through all of the above. PPL Electric Utilities meets its obligations to serve default service customers through a long term supply agreement with an affiliate, PPL EnergyPlus, that resulted from a competitive solicitation. The agreement expires at the end of the stranded collection period on December 31, 2009. The PPUC is currently in the process of defining the supply obligations for the default service provider.

7. How do non-utility retail service providers in the state secure access to transmission and distribution services needed to deliver power to their retail customers?

A non-utility retail service provider in Pennsylvania secures transmission service from PJM. The obligation to provide distribution services remains with the EDC.

8. What difficulties have retail supplier entrants encountered in entering the market? What conditions/incentives attract suppliers to retail markets?

In Pennsylvania, retail suppliers have encountered provider of last resort service at capped rates over a long transition period. As noted in response to Question B.1, above, these capped rates have, from time to time, been below the wholesale cost of service. Clearly, the current lack of competitive suppliers in certain Pennsylvania jurisdictions is the result of a conclusion on the part of those suppliers that they cannot earn a profit in those jurisdictions at this time. Important conditions/incentives that attract retail suppliers include a customer base that understands electric choice, and simple and standard business rules and infrastructure for transferring customer accounts.

D. Demand Side Participation

1. How do rate structures affect the incentives of large, medium, or small electric customers to participate in demand side response programs? Does this effect differ if a state has a retail choice program?

Even though Pennsylvania has retail choice, PPL Electric Utilities is still operating under rate caps that were established in 1997. These rates were based on the cost of service analysis performed at that time. The PPUC is currently in the process of establishing the regulations governing the supply and pricing of default service following the end of capped rates. For PPL Electric Utilities, the rate caps will expire on December 31, 2009.

PPL Electric Utilities does have several demand side response programs in which customers participate. For large industrial and commercial customers, an interruptible service rate exists for customers to reduce load during emergency and economic conditions. This rate currently has about sixty customers participating and in aggregate these customers represent approximately 250 MW of interruptible load. For residential customers, PPL Electric Utilities offers a Demand Side Response (“DSR”) Pilot program that time differentiates prices during the months of June through September. This program encourages customers to either reduce load during the on-peak periods or shift load to the off-peak periods. Currently 300 residential customers participate in this program.

2. What measures have states taken to make customer demand responsive to changes in availability and price of electricity supply? Do these measures differ if a state has a retail choice program?

In November 2000, the PPUC established a DSR Working Group after receiving comments from a DSR Roundtable that brought together all interested stakeholders. The working group was established to investigate DSR programs and develop policies to promote DSR.

In 2004, the Pennsylvania Alternative Energy Portfolio Standards Act was signed into law. The Act requires a certain percentage of the electric energy sold to retail customers in Pennsylvania be derived from alternative energy resources, which includes wind, solar, hydropower, geothermal, biomass, and demand side management resources. The PPUC is in the process of establishing the regulations for this Act.

3. What mechanisms allow for the participation of load response measures – interruptible load, self-generation, demand-side management, conservation and energy efficiency measures as alternatives in wholesale electric markets and or load serving utility resource portfolios? How has the performance of these measures been monitored?

The DSR programs that currently exist at PPL Electric Utilities include an Interruptible Service Rate for large industrial and commercial customers and a DSR Pilot program for residential customers. The interruptible program was established prior to retail choice and as of January 1, 2000 is not an available option for customers. For these customers, the interruptible load is monitored using interval metering. The residential DSR pilot program is limited to 300 customers and is currently fully subscribed. The customers were offered this rate option through a direct mail campaign based on eligibility requirements. Customer market research is used to determine the change in behavior of electricity use associated with this pilot program.

4. Have states adopted alternatives to average cost pricing to encourage demand response?

Even though Pennsylvania has retail choice, PPL Electric Utilities is still operating under rate caps that were established in 1997. These rates were based on the cost of service analysis performed at that time. The PPUC is currently in the process of establishing the regulations governing the supply and pricing of default service following the end of the rate caps. For PPL Electric Utilities, the rate caps will expire on December 31, 2009. Other states like New Jersey have required large commercial and industrial customers to move from average cost pricing to locational marginal pricing. In these markets, products and services have developed to assist customers in managing their demand.

5. What has been the effect on demand and demand elasticity in light of these measures?

PPL has no specific comment.

6. How prevalent is the use of distributed resources (e.g., distributed generation and distributed energy storage) within the state?

PPL has no specific comment.

7. To what extent are retail customers within the state or region increasing use of distributed resources and what types of resources are involved?

PPL has no specific comment.

E. Rising Fuel Prices

1. Are changes in prices for oil, natural gas, and coal affecting the results of competitive wholesale markets and viability of competitive suppliers and if so, why?

Yes. In the competitive wholesale markets, competitive suppliers adjust their energy pricing to reflect the changing replacement cost for fuels consumed by their generators. As a result, the increases in fuel prices that have occurred since the beginning of 2005 have caused on-peak and off-peak energy prices to increase. For example, actual average prices for the third quarter 2005 were about 60% higher than the forward prices for the third quarter that were trading at the beginning of 2005. This has resulted in increased costs for those companies who have not fully hedged the supply against their sales obligations.

In addition, the increase in fuel prices has resulted in increased forward prices for energy. Since the beginning of the year, PJM on-peak and off-peak forward energy prices for 2006 have increased by about 75% and 55% respectively.

2. How are the changes in prices for oil, natural gas, and coal affecting retail electricity prices?

The answer depends on the status of utility retail deregulation in a particular state or region. For companies like PPL, who are in the midst of their competitive transition period, during which the energy component of a default customer's rate is capped, there is very little economic incentive for customers to choose an alternate supplier since the "shopping credit" is less than the price that a competitive retail supplier could offer. In other states, like New Jersey, where a competitive auction is used to secure default supply for retail customers; the resulting prices from these competitive process has tracked the changes in prices for fuel and energy.

3. Competitive retail suppliers are also reflecting the change in fuel and energy prices as they price their products. Are there differences in retail price impacts between states and/or utility systems operating under retail competition models and those that operate under traditional utility cost based rate models?

Ultimately, rising fuel prices impact consumers in both retail competition and traditional utility cost-based models. However, given different aspects of traditional utility cost recovery, cost caps and transition periods, different segments (consumers, distributors or suppliers) may experience different impacts and may have different ways to handle recovery of increased costs. Fundamentally, significant fuel price increases will increase electricity prices, whether through competitive or regulatory cost recovery models.