ENVIRONMENTAL REPORT

CHAPTER 8

NEED FOR POWER

8.0 NEED FOR POWER

This chapter provides an assessment of the need for electric power in support of the Combined License Application (COLA) for the proposed Bell Bend Nuclear Power Plant (BBNPP). Also provided is a description of the existing regional electric power system, current and future demand for electricity, and present and planned power supplies.

This chapter supports the need for power generated by the BBNPP. The proposed U.S. Evolutionary Power Reactor (EPR) for BBNPP will have a rated design net electrical output of approximately 1,600 megawatts electric (MWe). The EPR will be constructed at the Bell Bend site and open for initial commercial operation in December 2018. The BBNPP will be a merchant facility owned by PPL Bell Bend, LLC (PPL) providing baseload energy for the electricity market.

The geographic scope or primary market area for the BBNPP has been generally defined as the eastern part of the PJM Interconnection, LLC (PJM) "classic" market area (Figure 8.2-1). PJM is the Regional Transmission Organization (RTO) that serves to maintain the reliability of the bulk electricity power supply system for 13 states and the District of Columbia. PJM serves approximately 51 million people and includes the major U.S. load centers from the western border of Illinois to the Atlantic coast including the metropolitan areas in and around Baltimore, Chicago, Columbus, Dayton, Newark and northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond, and Washington, D.C.

The eastern part of the PJM classic market area is a subset of the entire PJM area and is considered the Region of Interest (ROI) and primary market area for the BBNPP. The ROI/primary market area includes parts of the states of Pennsylvania, New Jersey, Delaware, Maryland, and Virginia. This area is closely approximated by the service territories for the electric delivery companies identified and depicted in Figure 8.2-1. For PPL and the corporation’s marketing entity, PPL EnergyPlus, key drivers for selecting this defined ROI/primary market area include:

- Fit with PPL EnergyPlus Marketing Plan – Assets and locations in the ROI/primary market area fit well with the PPL EnergyPlus marketing plan.

- Regulatory Environment – A thorough understanding of state regulatory issues is one of the most important considerations in developing a new generating facility. States within the ROI/primary market area, particularly Pennsylvania, are well understood from a regulatory perspective.

- Market Operations, RTO, independent system operator (ISO) – PJM is a mature, well functioning market that can readily fulfill PPL Corporation’s marketing objectives.

- Electric Transmission Concerns – The eastern part of the PJM classic market area provides access to several key market areas and is not subject to problems historically experienced by other regions in moving power to these markets.

- Probability of Success/Competitive Advantages - Assets for which there is expected to be less competition and where PPL has a competitive advantage rank highest. Examples of such advantages include negotiated deals, partially constructed assets, assets in which PPL has some involvement, and assets in markets that PPL understands thoroughly. The eastern part of the PJM classic market area, particularly where PPL Corporation already has assets, scores high in these considerations.

Reflecting historical power flows and constraints on the PJM transmission system, the ROI extends slightly west of the regulated service territory boundaries shown on Figure 8.2-1. This recognizes the advantages of situating the proposed facility east of PJM's western interface, which is often a point of constraint to the delivery of energy from western areas of PJM to eastern Pennsylvania, New Jersey, the Delmarva Peninsula and the Washington/Baltimore metropolitan area. Such placement would allow PJM to dispatch more cost effective generation located east of this interface to meet load demands, including periods when such constraints are experienced (PJM, 2008).

Limitations in the west-to-east transmission of energy across the Allegheny Mountains and the growing demand for baseload power at load centers along the east coast were factors in selecting the eastern part of the PJM classic market area. As a merchant plant, the ROI/primary market area is also based on PPL Corporation's fundamental business decisions on the economic viability of a nuclear power generating facility, the ROI/primary market for the facility's output, and the general geographic area where the facility should be deployed to serve the ROI/primary market area. Section 8.4.1 contains a discussion of companies considered probable competitors and their intentions to build new generating capacity in the PJM region.

The task of evaluating the region's power supply lies with the PJM RTO and the regional electric reliability organization RFC. PJM has projected continuing load growth in the primary market area. The DOE has identified New Jersey, Delaware, eastern Pennsylvania, and eastern Maryland as a Critical Congestion Area. PJM expects expanded exports of power into New York, further exacerbating the situation. Limitations in the west-to-east transmission of energy across the Allegheny Mountains and the growing demand for baseload power at load centers along the east coast were factors in selecting the eastern part of PJM's primary market area as the ROI.

One of PJM's objectives is to provide a transmission system that can accommodate power needs in all areas while maintaining a reliable network. The existing PJM high-voltage backbone transmission network provides lines appropriate for use by an EPR facility (500kV or 345 kV). In June 2007, PJM authorized a new 500 kV line connecting the existing Susquehanna 500 kV substation with the Roseland substation in northern New Jersey. This Susquehanna-Roseland line is being added independent of the proposals to construct BBNPP or other generating facilities. Planned to be in service by 2012, this line will become part of the "existing" transmission network for the BBNPP.

The Susquehanna-Roseland project addresses numerous overloads projected to occur on critical 230 kV circuits across eastern Pennsylvania and northern New Jersey, with multiple lines projected to exceed their conductor rating as early as 2013. (PJM, 2008) PJM regularly reviews performance issues associated with specific transmission facility overloads and outages as experienced in actual operations. This new circuit was justified on the basis of reliability as identified by reliability criteria violation tests in PJM's RTEP process deliverability studies. From an economic perspective, the line was not proposed to facilitate access of specific new generation proposals, even though this additional backbone capability can present economic opportunities for them. The ability of each generation request to interconnect safety and reliably is addressed in specific RTEP interconnection process studies.

Electricity used by consumers in the ROI/primary market area is bought and sold in the competitive wholesale electricity markets administered by PJM. PJM also coordinates reliability assessments with adjacent RTOs. While not the primary target market, available surplus electricity could be made available to adjacent RTOs when demand requires it. Generators that sell electricity in PJM, including the eastern part of the PJM classic market area, are contractually obligated to meet the reliability requirements as scheduled with PJM.

The Commonwealth of Pennsylvania deregulated electric utilities in 1996. Prior to deregulation, Pennsylvania and the Pennsylvania Public Utilities Commission (PPUC) took an active role in the management of the transmission system and determining where new power generation facilities were needed. Despite the deregulation of the price of electric supply and generation in Pennsylvania, the PPUC will continue to oversee electric service and competition from the 11 electric companies that provide electricity to the majority of Pennsylvania. Now, the regional entity, PJM, manages the electric system. Specifically, PJM attempts to work via market forces, encouraging independent owners to build the needed facilities. PJM only steps in and directs if the market does not appear to be providing sufficient incentive to ensure continuing system reliability (PJM, 2007). Various subsidiaries of PPL Corporation are members of PJM and ReliabilityFirst Corporation (RFC).

In 1999, the Delaware General Assembly passed legislation restructuring the electric industry in Delaware. Prior to restructuring, the generation, transmission, and distribution of electric power by investor-owned utilities was fully regulated by the Delaware Public Service Commission (DPSC). With restructuring, the generation of electric power became deregulated, leaving only distribution services under the regulatory control of the DPSC.

In 2006, faced with significantly increased energy costs, the Delaware General Assembly passed a revision to the restructuring legislation entitled "The Electric Utilities Retail Supply Act of 2006" (Delaware General Assembly, 2006). The Act provides that all electric distribution companies subject to the jurisdiction of the DPSC would be designated as the standard offer service supplier and returning customer service supplier in their respective territories. The Act provided further opportunity for distribution companies to enter into long and short-term supply contracts, own and operate generation facilities, build generation and transmission facilities, make investments in demand-side resources and take any other DPSC-approved action to diversify their retail load supply. Additionally, Delmarva Power is required to conduct Integrated Resource Planning (IRP) for a forward-looking 10-year timeframe and to file such plan with the DPSC, the Controller General, the Director of the Office of Management and Budget, and the Energy Office every 2 years starting with December 1, 2006. As part of the initial planning process, Delmarva Power is required to file a proposal to obtain long-term supply contracts. The proposal requires Delmarva Power to include a Request for Proposal (RFP) for the construction of new generation resources within Delaware.

In 1999, New Jersey electricity customers became able to choose a company that will supply them with electric power. This choice is available due to the enactment of the "Electric Discount and Energy Competition Act" which, among other things, allows competition in the power generation portion of the electric industry (New Jersey General Assembly, 1999).

The New Jersey Board of Public Utilities' (NJBPU) Office of Clean Energy developed the CleanPower Choice Program, a statewide program that allows customers to support the development of clean, renewable sources of energy. Because of the new state law, the different responsibilities of the utilities were "unbundled" and the power industry was separated into four divisions: generation, transmission, distribution, and energy services. The generation sector has been deregulated and, as a result, utilities are no longer the sole producers of electricity. The transmission and distribution sectors remain subject to regulation – by either the federal government or the NJBPU.

Effective July 2000, the Maryland Electric Customer Choice and Competition Act of 1999 restructured the electric utility industry in Maryland to allow electric retail customers to shop for power from various suppliers (State of Maryland, 1999). These retail suppliers can generally be grouped into two categories:

- Local Utility – Entity that supplies electricity as a regulated monopoly and is the current default provider of electricity supply for customers who do not choose an alternative competitive electricity supplier.

- Competitive Suppliers – Competing entities that began supplying electricity in the competitive marketplace when the market was restructured.

Prior to restructuring, the local electric utility operated as a regulated, franchised monopoly. It supplied all end-use customers within its franchised service area with the three principal components of electric power service: generation, transmission, and distribution. With the restructuring of the electric power industry in Maryland, generation of electricity is now provided in a competitive marketplace (transmission and distribution remain regulated monopolies). Prices for power supply are determined by a competitive electric power supply market rather than by the Maryland Public Service Commission (MDPSC) in a regulated environment.

As in other states, Virginia's electrical industry is in transition due to deregulation. Prior to deregulation, most electrical generation plants, and all electrical transmission and distribution facilities in the state were operated by public utilities - private firms licensed to provide electrical power within Virginia under state-regulated pricing. The deregulation process has the potential to result in a competitive market for electrical energy supplies. Although electrical energy distribution remains regulated, both the state's public utilities and non-utility generating firms provide electrical power supplies.

Through changes in state law by the Virginia General Assembly in 1999, the Commonwealth initiated the transition toward a competitive energy supply market to be in place by 2007. For the first time, Virginians were being given the opportunity to decide who supplies their electricity or natural gas. In the past, one company provided all energy services – generation/ supply, transmission, and distribution. This change of the state law allowed for more than one company to supply electricity or natural gas, thus allowing customers to shop for the most attractive offer. What remained unchanged was that local utility companies continue to distribute and deliver electricity or natural gas to homes and businesses. The Virginia State Corporation Commission (SCC) continues to regulate such distribution. The Virginia General Assembly specifically charged the SCC with advancing competition and working through the complex details of moving the industry from one that is governed by regulators to one that is governed by the market.

In 2007, the Virginia General Assembly passed legislation (Senate Bill [SB] 1416 and House Bill [HB] 3068) re-establishing retail rate regulation for most of the electricity customers in the Commonwealth (Virginia General Assembly, 2007a and 2007b). Electricity customers with annual demands greater than 5 megawatts (MW) continue to have the option to shop for competitive electricity supply. In addition, this legislation allows retail customers to purchase electricity supply from 100% renewable sources from competitive suppliers if their local utility company does not include renewable energy as a source of generation.

This chapter demonstrates the need for the power to be generated by the facility and related benefits. This demonstration is supported by an analysis for the need for power, which is organized into the following four sections:

- Description of Power System (Section 8.1)
- Power Demand (Section 8.2)
- Power Supply (Section 8.3)
- Assessment of Need for Power (Section 8.4)

Since the deregulation of electric utilities in the ROI/primary market area, the task of evaluating the region's power supply is conducted by the PJM RTO and the regional electric reliability organization (ERO), RFC. The following sections of this chapter demonstrate that the PJM reliability evaluation process satisfies the NRC criteria and is adequate for supporting the need for power analysis in this ER. While PPL is the license applicant, PJM is the entity responsible for delivering electric power to its member electricity distributors. This commitment to provide power to its electricity distribution members requires PJM to prepare need for power analyses including forecasting future demands and evaluating reliability. This commitment also shows that the PJM reliability evaluation process meets the characteristics of an acceptable analysis of the need for power that satisfies NUREG 1555.

8.0.1 REFERENCES

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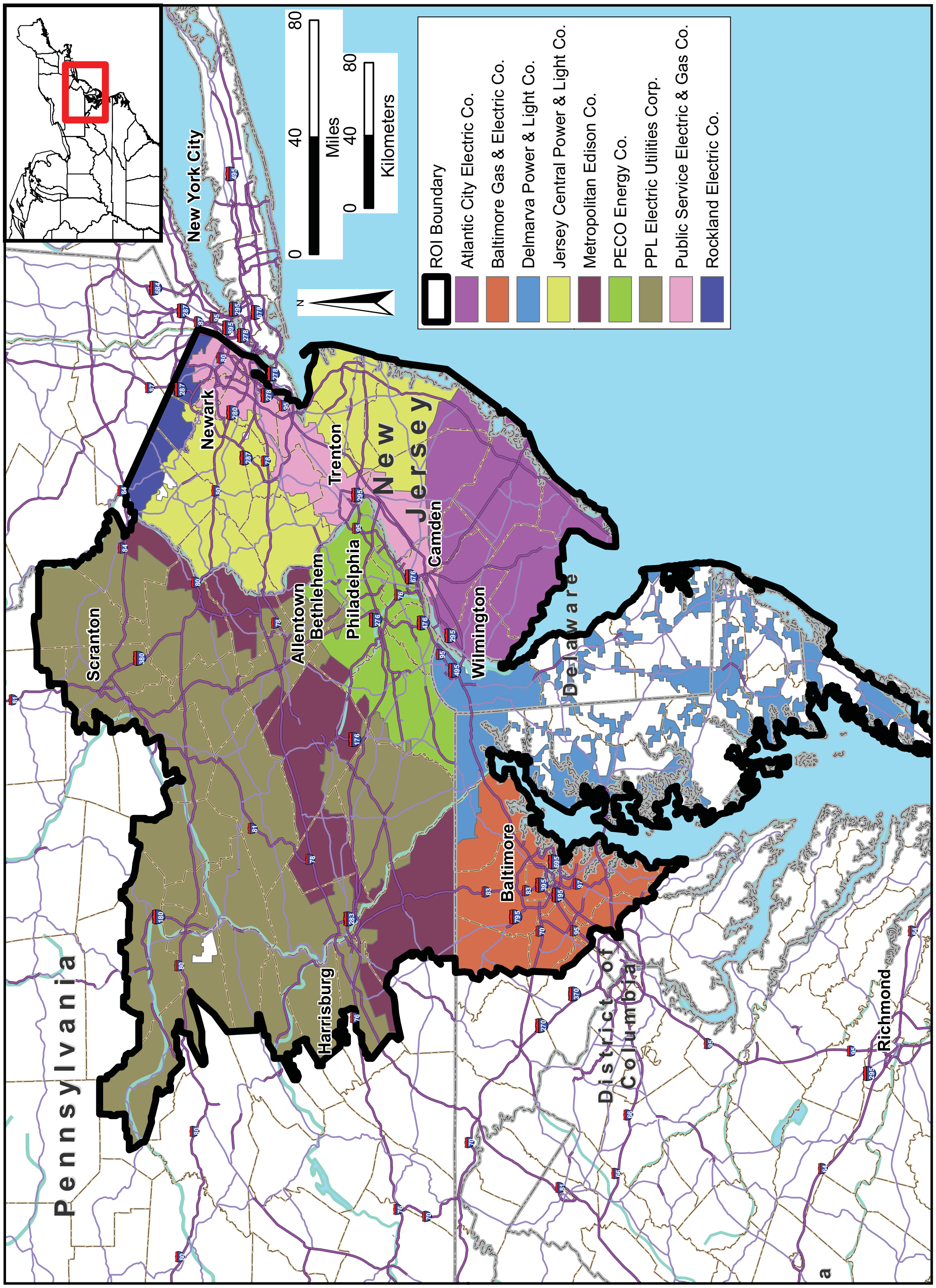
Virginia General Assembly, 2007b. "HB 3068, Electric Utility Service; Advances Scheduled Expiration of Capped Rate Period," 2007.

Figure 8.0-1—Primary Market Area - Region of Interest



8.1 DESCRIPTION OF POWER SYSTEM

This section describes the power system in the eastern part of the PJM classic market area and how the PJM reliability evaluation process satisfies the criteria listed in NUREG-1555. The four criteria of the NRC for need for power analysis (1) systematic, 2) comprehensive, 3) subject to confirmation, and 4) is responsive to forecasting uncertainties), are discussed in Section 8.1.1 through Section 8.1.4. These sections show the PJM reliability processes satisfy these four criteria, and are adequate for supporting the BBNPP need for power analysis.

PPL Corporation is an energy and utility holding company that, through its subsidiaries, generates electricity from power plants in the northeastern and western U.S. PPL Corporation also markets wholesale or retail energy primarily in the northeastern and western portions of the U.S. and delivers electricity to approximately 4 million customers in Pennsylvania and the U.K.

PPL Corporation has a number of independent subsidiaries including PPL Energy Supply, LLC (PPL Energy Supply) and PPL Electric Utilities Corporation (PPL EU). PPL Energy Supply is an indirect wholly-owned subsidiary of PPL Corporation whose major operating subsidiaries are PPL Generation, LLC (PPL Generation), PPL EnergyPlus, LLC (PPL EnergyPlus) and PPL Global, LLC (PPL Global). PPL EU is a direct subsidiary of PPL Corporation and a regulated public utility.

PPL Corporation is organized into segments consisting of Supply, Pennsylvania Delivery, and International Delivery. PPL Energy Supply's segments consist of Supply and International Delivery. The Supply segment owns and operates domestic power plants to generate electricity, markets this electricity and other power purchases to deregulated wholesale and retail markets, and acquires and develops domestic generation projects. The Supply segment consists primarily of the activities of PPL Generation and PPL EnergyPlus.

PPL Generation's U.S. generation subsidiaries are exempt wholesale generators (EWGs), which sell electricity into the wholesale market. As of December 31, 2007, PPL Generation owned or controlled generating capacity of 11,418 MW. Through subsidiaries, PPL Generation owns and operates power plants in Pennsylvania, Montana, Illinois, Connecticut, New York, and Maine. In Pennsylvania, PPL Generation power plants had a total capacity of 9,076 MW on December 31, 2007. These power plants are fueled by uranium, coal, natural gas, oil, and water (PPL, 2008).

The electricity from these plants is sold to PPL EnergyPlus under FERC-jurisdictional power purchase agreements. PPL EnergyPlus, in-turn, markets or brokers the electricity produced by PPL Generation subsidiaries, along with purchased power, natural gas and oil, in competitive wholesale and deregulated retail markets in order to take advantage of opportunities in the competitive energy marketplace.

The Pennsylvania Delivery segment includes the regulated electric delivery operations of PPL EU, one of the potential customers for output from BBNPP. In its Pennsylvania service territory, PPL EU delivers electricity to approximately 1.4 million customers in a 10,000 square mile (mi^2), 25,900 square kilometer (km^2) territory in 29 counties in the eastern and central part of the state. In addition to delivering electricity in its service territory in Pennsylvania, PPL EU also provides electricity supply to retail customers in that territory as a provider of last resort (PLR) under Pennsylvania's Customer Choice Act (PPL, 2008).

In 2006, PPL EU had energy sales totaling 37.7 billion kilowatt hours (kWh), a decrease of 1.6% from 2005 sales. A partial explanation for this decrease is PPL EU's report of a peak load reduction of 246.5 MW and energy savings of 2.6 million kWh in 2006, resulting from its Interruptible Service – Economic Provisions tariff schedule. Customers reducing load for economic conditions receive significant rate discounts from PPL EU. Additionally, the PPL EU Price Response Service permits customers to respond to market price signals by reducing a portion of their load. In 2006, PPL EU reported that an estimated 1,100 kilowatt (kW) peak load reduction was achieved, with energy savings totaling 29,600 kWh. In addition, for PPL EU customers, the Residential Side Response Rider, which provides for the option of shifting load from peak hours, reduced the peak by 104 kW and saved 60,435 kWh (PPUC, 2007a).

Table 8.1-1 (PPUC, 2007a) provides information on PPL EU's historical and future energy demands, which grew at an average rate of 1.9% per year from 1991 to 2006. During this timeframe, residential demand grew by 1.9%, commercial by 2.7%, and industrial by 0.9%.

Table 8.1-2 through Table 8.1-5 (PPUC, 2007a) provide PPL EU's actual and forecasted peak load, and residential, commercial, and industrial energy demand from 1997 through 2007.

PPL Generation's net operable generating capacity includes 43.4% coal fired capacity and 23.8% nuclear capacity. Natural gas and dual fuel units account for 26.1% of the total. Independent power producers also provided 303 MW to the system. In 2006, PPL purchased more than 2.4 billion kWh from cogeneration and independent power production facilities, or approximately 6.4% of total sales.

On June 13, 2007, PPL Corporation announced that it had taken steps to preserve the option to build a third nuclear power generating unit adjacent to the Susquehanna Steam Electric Station (SSES) near Berwick, Pennsylvania. The two existing nuclear units have a total combined capacity of 2,360 MW (PPUC, 2007a).

This proposed nuclear power generating unit (BBNPP) lies within the PJM RTO. All connections to the transmission system will be on the BBNPP project site, so consideration of alternative transmission routes is not necessary for this project. One direct connection to the transmission system is via an expansion of the existing Susquehanna 500 kV Yard with its two circuits (Wescosville and Sunbury). A second direct connection will be provided by a new 500-kV transmission system switchyard (Susquehanna 500 kV Yard 2) that will be constructed for the BBNPP project on the project site. This second switchyard will ultimately connect BBNPP with a 500 kV circuit that is being planned and constructed by PPL EU for PJM independent of, and without consideration for, the BBNPP project. This new circuit, planned to be placed in service by 2012, will initially connect the existing Susquehanna 500 kV Yard with the Roseland substation in New Jersey. The new transmission system switchyard being constructed for the BBNPP will break this line, creating a new outlet terminus for the BBNPP switchyard, and providing a connection between the two 500-kV transmission switchyards as shown in Figure 3.7-2.

No additional transmission corridors or other offsite land use will be required to connect the new reactor unit to the transmission grid. The following facilities will be constructed within the BBNPP project area:

- One new 500 kV BBNPP switchyard to transmit power from the BBNPP
- One new 500-kV transmission system switchyard (Susquehanna 500 kV Yard 2) to provide an additional outlet point to the transmission system
- Expansion of the existing Susquehanna 500 kV Yard

- Two new 500 kV, 4,260 MVA circuits, on individual towers, connecting the BBNPP switchyard to the expanded Susquehanna 500 kV Yard, and the new Susquehanna 500 kV Yard 2.

PJM defines any additional transmission system improvements that might be needed. PPL EU, which is regulated by the PPUC, has responsibility for the planning, construction, and routing of connecting transmission lines. PPL EU responsibilities within their service territory include:

- Defining the nature and extent of system improvements
- Designing and routing connecting transmission
- Addressing the impacts of such improvements

In accordance with the PJM Open Access Transmission Tariff (OATT), any parties wishing to connect a new generation resource to the PJM system must submit an Interconnection Request. To obtain approval of an interconnection request, PJM conducts three stages of reviews which impose increasing financial obligations on the requesting party, and establishes PJM milestone responsibilities.

The process includes Feasibility Studies (first stage), System Impact Studies (second stage), and Facilities Studies (third and final stage). Each step assesses reliability impacts of the proposed facility connecting to the PJM system, and they provide increasing refined extimates of the costs and network upgrades required for the proposed interconnection.

In September 2008, PJM completed the second stage of the process by issuing the PJM Generator Interconnection R01/R02 Susquehanna 1,600-MW Impact Study Re-study (PJM, 2008a.) This study evaluated the proposed BBNPP 1,600 MW nuclear power generating facility. Reliability criteria for summer peak conditions in 2012 were used for evaluating compliance of the project (BBNPP). The study concluded that the BBNPP project can be connected to the 500 kV system by expanding the existing Susquehanna 500 kV Yard and building two new 500-kV switchyards.

As noted in Section 8.0, various subsidiaries of PPL Corporation are members of PJM and RFC. The predecessor company to PPL Corporation was one of the original three members of PJM. PPL EnergyPlus is a voting member of PJM and PPL EU and the PPL Generation subsidiary companies are affiliates of PJM. PJM has ensured that electricity is reliably provided in its region for about 80 years. PJM was formed in 1927 as the world's first continuing power pool when three utilities in Pennsylvania and New Jersey realized the benefits and efficiencies of sharing resources. PJM opened the country's first wholesale energy market in 1997. PJM, as an Regional Transmission Organization (RTO), is responsible for the safe and reliable operation of the transmission system in its region, as well as administration of competitive wholesale electricity markets (PJM, 2006).

PJM serves approximately 51 million people and includes the major U.S. load centers from the western border of Illinois to the Atlantic coast. These load centers include the metropolitan areas in and around Baltimore, Chicago, Columbus, Dayton, Newark, northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond, and Washington D.C. PJM has more than 500 members and dispatches more than 165,000 MW of generation capacity over 56,000 miles (mi), 90,123 kilometers (km), of transmission lines — a system that serves nearly 20% of the U.S. economy (PJM, 2008b).

As the RTO, PJM also performs systematic reliability planning (PJM, 2007a). PJM's Capacity Adequacy Planning Department is responsible for determining and monitoring the generation reliability requirements of PJM. This includes analyzing the growth of electrical peak load within the region (Brattle, 2006). Also, PJM continues to focus on planning the enhancement and expansion of transmission capability on a regional basis.

In addition, PJM operates the transmission system that is used to provide transmission service. Transmission services include Point-To-Point transmission service (long-term and short-term firm and non-firm) and Network Integration transmission service. In carrying out this responsibility, PJM performs the following functions:

- Acts as transmission provider and system operator for the PJM region
- Maintains the Open Access Same-Time Information System (OASIS)
- Receives and acts on applications for transmission service
- Conducts system impact and facilities studies
- Schedules transactions
- Directs re-dispatch, curtailment, and interruptions
- Accounts for, collects, and disburses transmission revenues

To be compliant with FERC Order 888, the transmission owners (TOs) in PJM filed with the FERC an open access transmission service tariff, called the PJM Open Access Transmission Tariff (OATT). Transmission open access provides the ability to make use of existing transmission facilities that are owned by others, in this case the TOs, in order to deliver power to customers. Transmission service is the reservation to transport power from one point to another and all of the ancillary services that are necessary to make the transport of power possible. The PJM TOs' transmission facilities are operated with free-flowing transmission ties. PJM manages the operation of these facilities, in accordance with the PJM Operating Agreement.

Each TO in PJM is a signatory to the PJM OATT. They collectively have delegated the responsibility to administer the PJM OATT to PJM. Each TO has the responsibility to design or install transmission facilities that satisfy requests for transmission service under the tariff.

PJM has recently developed independent load forecasting procedures to enhance reliability planning and transmission expansion. For example, reliability planning was previously based on individual reports from each transmission zone within PJM. Each submitting entity produced its forecast based on its own methodology, although it was common that the energy forecast was derived from company retail sales forecasts. An energy forecast was then used to derive the peak load forecast. After receiving these individual forecasts, PJM would prepare a report showing the aggregate coincident and non-coincident peak reports and release these to the public (PJM, 2007a).

With the advent of electric industry restructuring, PJM, as the RTO, determined that a single independent forecast should replace the diversified "sum of zones" report. In 2004, PJM began developing its forecast model and framework. PJM performs an independent forecast to determine the need for transmission improvements and expansion in the PJM Regional Transmission Expansion Plan (RTEP) using data inputs from its members. The latest transmission expansion report notes plans for new capacity, as well as dynamic growth forecasts (PJM, 2008b).

PJM employs an operating procedure known as economic dispatch to minimize fuel costs for all members. With economic dispatch, a utility system makes maximum use of its lowest operating cost generating units (coal and nuclear plants) and only uses more expensive units (oil or gas fired) when the less expensive units are already running at their maximum levels. PJM implements this process by collecting plant operating data on all member plants and continuously determining the pool-wide cost of generating an additional kWh (the incremental cost). It operates all of the members' units as a single system, in which generation is added from the most economical source available (regardless of ownership) to meet the next increment of load. These inter-company power transactions are referred to as interchanges. Through this system of economic dispatch, PJM gains cost savings and distributes those savings among its members. PJM’s market area is one of the sub-regions of the RFC.

In Pennsylvania and the other states in the ROI/primary market area, all major electric utilities are interconnected with neighboring systems extending beyond state boundaries. These systems are organized into regional reliability councils that are responsible for ensuring the reliability of the electric system (PPUC, 2007a). The RFC is one of the eight approved regional entities in North America, under NERC. The RFC serves the states of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, Wisconsin, and the District of Columbia. The RFC coordinates with utilities and sets forth criteria for planning adequate levels of generating capacity. The criteria consider load characteristics, load forecast error, scheduled maintenance requirements, and the forced outage rates of power generating units. Reliability standards for the RFC require that sufficient generating capacity be installed to ensure that the probability of system load exceeding available capacity is no greater than 1 day in 10 years. The load serving entities have a capacity obligation determined by evaluating individual system load characteristics, unit size, and operating characteristics.

The RFC and the Midwest Reliability Organization (MRO) entered into a coordination agreement in March 2006 for the purpose of coordinating the development of reliability standards and compliance and enforcement procedures; cooperating on the development and procedures employed to conduct power system analysis, studies, and evaluations between the regions; and facilitating efficient and effective administration of MRO and RFC duties.

8.1.1 SYSTEMATIC PROCESS

The PJM reliability planning process is systematic because it consists of steps that can be independently replicated. The process is well documented, evolving, and completed on an annual basis (PJM, 2008b). The PJM reliability planning process is also confirmable by comparing forecasts to RFC composite forecasts. For almost 80 years, PJM has ensured that electric power is reliably provided in the region. As an RTO, PJM is responsible for the safe and reliable operation of the transmission system in its region, as well as administration of competitive wholesale electricity markets. Additionally, PJM is responsible for managing changes and additions to the grid to accommodate new generating plants, substations, and transmission lines. PJM not only analyzes and forecasts the future electricity needs of the region, but it also ensures that the growth of the electric system takes place efficiently, in an orderly, planned manner, and that reliability is maintained.

Many planning processes go into PJM’s determining of the need for power. These processes are documented and published to assure that the planning process is transparent. The processes include reliability planning, including expansion planning, reliability assessments, and economic planning; and resource adequacy planning, including load forecast development processes. In addition, the process includes stakeholder participation through the PJM Transmission Expansion Advisory Committee (TEAC). As noted in Section 8.1, PJM annually develops its RTEP in a participatory and open transmission planning process with the advice and input of the TEAC (PJM, 2008b). These planning processes are described further throughout this chapter, specifically in Section 8.2.

8.1.2 COMPREHENSIVE PROCESS

As part of the annual RTEP process, PJM performs comprehensive power flow, short circuit, and stability analyses. These analyses evaluate potential impacts of forecasted firm loads, firm imports from and exports to neighboring systems, existing generation and transmission assets, and anticipated new generation and transmission facilities. PJM also conducts a comprehensive assessment of the ability of the PJM system to meet all applicable reliability planning criteria (PJM, 2008b). Reliability planning criteria considered include the following:

- NERC planning criteria
- RFC reliability principles and standards
- Southeastern Electric Reliability Council (SERC) planning criteria
- Nuclear plant licensee requirements
- PJM reliability planning criteria, per Manual M14B
- Transmission owner reliability planning criteria, per their respective FERC 715 filings.

8.1.3 CONFIRMATION PROCESS

The PJM regional planning process is conducted in the RTEP protocol set forth in Schedule 6 of the PJM Operating Agreement. The PJM RTEP process was developed under a FERC approved RTO model that encompasses independent analysis, recommendation, and approval to ensure that facility enhancements and cost responsibilities can be identified in a fair and non-discriminatory manner, free of any market sector's influence. The ability of PJM to evaluate the generation and merchant transmission interconnection requests is codified under Part IV of the PJM OATT (PJM, 2007b). These procedures are documented and conducted consistently each time, demonstrating that the process is systematic and subject to confirmation. The process is well documented, evolving, and completed on an annual basis (PJM, 2008b). All expansion plans developed by PJM conform to the reliability standards and criteria specified by NERC and the applicable regional reliability council, the various nuclear plant licensees' Final Safety Analysis Report (FSAR) grid requirements and the PJM reliability planning criteria (PJM, 2007b). In addition, PJM submits capacity and demand forecasting reports to the RFC. The RFC is one of the eight NERC approved regional entities in North America, and it gathers similar power planning information from other RTOs in its region for use in its own system planning. The forecasting reports that are filed with the RFC are also filed with FERC.

8.1.4 CONSIDERATION OF UNCERTAINTY

The process conducted by PJM is responsive to forecasting uncertainty. The factors in the model, such as temperature and economic conditions, include certain levels of uncertainty. For instance, higher electricity prices and viable demand side response (DSR) programs might not result in a reduction in electricity demand. Overall, PJM recognizes that uncertainties in market trends, income, population growth, demand, and fuel supply diversity will remain significant in forecast methodology (PJM, 2007c).

As an example, in its annual reliability report, the PPUC notes the basic uncertainties of forecasting electricity consumption on a long term basis and that actual demand could vary significantly, particularly in the years calculated for the end of the 10 year analysis period. A number of Pennsylvania specific factors add to this unpredictability. For example, the elasticity of consumer response to sharply higher electricity prices, on a short term basis and on a long term basis, is very difficult to forecast. Customers might not reduce demand for electricity as much as one might otherwise expect in the face of higher prices and widespread availability of demand reduction programs. On the other hand, these price signals could help force demand response and energy efficiency programs, ultimately causing consumer demand to fall short of levels projected by PJM reliability studies and the utilities. Given the long lead times required to plan and construct generation and transmission facilities, and current shortages of both forms of infrastructure in Pennsylvania, the PPUC recognizes that it needs to assess the extent to which it can rely on the most optimistic and most pessimistic of the load forecasts (PPUC, 2007b).

NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC develops and publishes annual long term reliability assessment reports to assess the adequacy of the bulk electric system in the United States and Canada over a 10 year period, including summer and winter assessments, and special regional, interregional, or interconnection assessments as needed. These reports project electricity supply and demand, evaluate transmission system adequacy, and discuss key issues and trends that could affect reliability (NERC, 2007).

The purpose of the regional entities under NERC is to ensure the adequacy, reliability, and security of the bulk electric supply systems of the region through coordinated operations and planning of their generation and transmission facilities.

8.1.5 CONCLUSION

As described in the preceding sections, the PJM reliability evaluation process is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) is responsive to forecasting uncertainties. Therefore, the PJM process is responsive to its data and information needs of Sections 8.1, 8.2, 8.3, and 8.4 as described in NUREG-1555.

8.1.6 REFERENCES

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Table 8.1-1—PPL EU Historic and Future Energy Demand

	Percentage of PPL EU Market in 2006	Annual Energy Demand Growth 1991–2006	5-Year Projection of Average Growth
Residential	36.3%	1.9%	1.6%
Commercial	34.8%	2.7%	1.7%
Industrial	25.7%	0.9%	0.8%
Overall Average		1.9%	1.4%

Table 8.1-2—PPL EU Actual and Projected Peak Load (MW)

Year	Actual Peak Load	Projected Peak Load Requirements										
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1997	5,925	6,910	-	-	-	-	-	-	-	-	-	-
1998	6,688	6,935	6,910	-	-	-	-	-	-	-	-	-
1999	6,746	7,030	6,935	6,815	-	-	-	-	-	-	-	-
2000	6,355	7,120	7,030	6,905	6,580	-	-	-	-	-	-	-
2001	6,583	7,130	7,120	7,006	6,680	6,850	-	-	-	-	-	-
2002	6,970	7,250	7,130	7,040	6,770	6,960	7,000	-	-	-	-	-
2003	7,197	7,350	7,250	7,140	6,860	7,060	7,070	6,790	-	-	-	-
2004	7,335	7,470	7,350	-	6,960	7,170	7,040	6,860	7,200	-	-	-
2005	7,083	7,580	7,470	-	-	7,270	7,120	7,000	7,300	7,200	-	-
2006	7,577	7,690	7,580	-	-	-	7,200	7,140	7,410	7,290	7,310	-
2007	-	-	7,690	-	-	-	-	7,320	7,510	7,390	7,410	7,200
2008	-	-	-	-	-	-	-	-	7,610	7,490	7,510	7,270
2009	-	-	-	-	-	-	-	-	-	7,580	7,610	7,340
2010	-	-	-	-	-	-	-	-	-	-	7,710	7,400
2012	-	-	-	-	-	-	-	-	-	-	-	7,480

Note:
MW = megawatts

Table 8.1-3—PPL EU Actual and Projected Residential Energy Demand (GWh)

Year	Actual Energy Demand	Projected Residential Energy Demand										
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1997	11,434	11,690	-	-	-	-	-	-	-	-	-	-
1998	11,156	11,760	11,690	-	-	-	-	-	-	-	-	-
1999	11,704	11,830	11,760	11,740	-	-	-	-	-	-	-	-
2000	11,923	11,910	11,830	11,850	12,031	-	-	-	-	-	-	-
2001	12,269	12,020	11,910	11,980	12,150	12,176	-	-	-	-	-	-
2002	12,640	12,160	12,020	12,120	12,280	12,324	12,391	-	-	-	-	-
2003	13,266	12,290	12,160	12,260	12,421	12,478	12,514	12,868	-	-	-	-
2004	13,441	12,430	12,290	-	12,562	12,634	12,650	13,062	13,308	-	-	-
2005	14,218	12,570	12,430	-	-	12,799	12,803	13,259	13,505	13,950	-	-
2006	13,714	12,710	12,570	-	-	-	12,955	13,462	13,728	14,311	14,099	-
2007	-	-	12,710	-	-	-	-	13,671	13,962	14,675	14,392	14,180
2008	-	-	-	-	-	-	-	-	14,198	15,019	14,555	14,422
2009	-	-	-	-	-	-	-	-	-	15,349	14,794	14,565
2010	-	-	-	-	-	-	-	-	-	-	15,036	14,702
2012	-	-	-	-	-	-	-	-	-	-	-	14,828

Note:
GWh = gigawatt hour

Table 8.1-4—PPL EU Actual and Projected Commercial Energy Demand (GWh)

Year	Actual Energy Demand	Projected Commercial Energy Demand										
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1997	10,309	10,490	-	-	-	-	-	-	-	-	-	-
1998	10,597	10,740	10,490	-	-	-	-	-	-	-	-	-
1999	11,002	11,000	10,740	10,740	-	-	-	-	-	-	-	-
2000	11,477	11,280	11,000	10,980	11,090	-	-	-	-	-	-	-
2001	11,778	11,560	11,280	11,240	11,275	11,291	-	-	-	-	-	-
2002	12,117	11,870	11,560	11,500	11,444	11,431	11,850	-	-	-	-	-
2003	12,273	12,140	11,870	11,760	11,612	11,561	12,033	12,212	-	-	-	-
2004	12,576	12,410	12,140	-	11,782	11,699	12,219	12,507	13,275	-	-	-
2005	13,157	12,680	12,410	-	-	11,848	12,411	12,757	13,601	12,967	-	-
2006	13,140	12,940	12,680	-	-	-	12,602	13,101	13,975	13,436	13,188	-
2007	-	-	12,940	-	-	-	-	13,418	14,286	13,946	13,562	13,184
2008	-	-	-	-	-	-	-	-	14,631	14,517	13,836	13,476
2009	-	-	-	-	-	-	-	-	-	15,068	14,166	13,777
2010	-	-	-	-	-	-	-	-	-	-	14,492	14,045
2012	-	-	-	-	-	-	-	-	-	-	-	14,290

Note:
GWh = gigawatt hour

Table 8.1-5—PPL EU Actual and Projected Industrial Energy Demand (GWh)

Year	Actual Energy Demand	Projected Industrial Energy Demand										
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1997	10,078	10,070										
1998	10,220	10,110	10,070									
1999	10,179	10,270	10,110	10,190								
2000	10,280	10,440	10,270	10,350	10,543							
2001	10,319	10,610	10,440	10,520	10,836	10,963						
2002	9,853	10,790	10,610	10,690	11,077	11,255	10,780					
2003	9,599	10,960	10,790	10,860	11,295	11,521	11,135	10,355				
2004	9,611	11,140	10,960		11,498	11,777	11,425	10,503	9,938			
2005	9,720	11,320	11,140			12,010	11,702	10,641	10,035	9,750		
2006	9,704	11,510	11,320				11,970	10,795	10,155	9,926	9,968	
2007			11,510					10,924	10,253	10,136	10,048	9,965
2008									10,346	10,349	10,084	9,999
2009										10,577	10,150	10,032
2010											10,214	10,059
2012												10,084

Note:
GWh = gigawatt hour

8.2 POWER DEMAND

This section contains information about the anticipated electrical demands, as well as the factors affecting power growth and demand in the primary market area. This section also describes the power resource adequacy review performed by PJM.

The need for power establishes a framework for analysis of project benefits and for the geographic boundaries over which benefits and costs are distributed. Because the BBNPP will be developed as a merchant facility, power generated could be distributed to PJM electricity distributor members or it could be sold outside the relevant primary market area boundary. While these distribution options are possible, market forces coupled with generation and transmission capabilities and load demands result in a strong partiality toward sales within the ROI/primary market area. Merchant facilities have the ability to sell energy to anyone, and they are only limited by the transmission system. PJM also imports and exports energy to and from other regions. The largest number of energy exports was to the Tennessee Valley Authority (TVA), MidAmerican Energy Company, and NYISO. The largest number of energy imports was from Ohio Valley Electric Corporation, Illinois Power Company, and Duke Energy Corporation.

As previously stated in Section 8.0, BBNPP is proposed as a baseload facility. Baseload facilities typically produce larger amounts of energy, run most of the time, and provide a constant source of power to the energy grid. Intermittent facilities are generally used to augment the need for baseload power when demand exceeds capacity. Peaking facilities have no reserves and little capacity, and are used in response to high levels of demand for energy. Baseload and peaking generation is discussed further in Section 8.3

8.2.1 POWER AND ENERGY REQUIREMENTS

As the RTO, one of PJM's primary functions is planning the enhancement and expansion of transmission capability on a regional basis. Key systematic and comprehensive components of PJM's 15 year regional planning protocol include baseline reliability upgrades, generation and transmission resource interconnection upgrades, and market efficiency driven upgrades (PJM, 2007a).

As described in Section 8.1.1, PJM's regional planning process is systematic and subject to confirmation. All expansion plans developed by PJM conform to the reliability standards and criteria specified by NERC and the applicable regional reliability council, the various nuclear plant licensees' FSAR grid requirements and the PJM reliability planning criteria (PJM, 2007a).

Power demand can best be analyzed by evaluating its two major components: power and energy requirements, and factors affecting growth of demand. This section provides relevant information about electrical demand, demand growth in the region, and other factors affecting the need for new power.

As noted above, the BBNPP will be developed as a merchant plant with the ability to serve customers in the ROI/primary market area, the eastern part of the PJM classic market area. Historical and forecasted load information for the ROI/primary market area was taken from the PJM load forecasting model. As the RTO for the region, PJM calculates long term forecasts of peaks, net energy, and load management for zones and regions in the RTO.

As discussed in Section 8.1, with deregulation and the development of retail choice in some jurisdictions in 1999, several factors led to the decision to develop an independent PJM load forecast to replace the diversified sum of zones forecast. PJM performs in independent forecast to determine the need for transmission improvements and expansion,based on input from its electricity distribution members.

PJM produces and publishes an annual peak load and energy forecast report. The load forecasting models are needed to provide input into the RTEP and the Installed Reserve Margin (IRM) Study (PJM, 2007b). The long term daily non-coincident peaks (NCP) model is a linear regression model of daily NCP loads. Separate models were used for each PJM zone using NCP loads as the dependent variable. The model is systematic in that it uses the same structure for each zone; however, the model develops a set of model coefficients specific to each zone (PJM, 2007c).

The PJM Load Forecast Model employs econometric multiple regression processes to estimate and produce 15-year monthly forecasts of unrestricted peaks assuming normal weather for each PJM zone and the RTO. The model incorporates three classes of variables: (1) calendar effects, such as day of the week, month, and holidays, (2) economic conditions, and (3) weather conditions across the RTO (PJM, 2007c). The model is used to set the peak loads for capacity obligations, for reliability studies, and to support the RTEP. PJM uses gross metropolitan product (GMP) in the econometric component of its forecast model. This allows for a localized treatment of economic effects within a zone. A private contractor for all areas within the PJM ROI/market area provides ongoing economic forecasts. Weather conditions across the region are considered by calculating a weighted average of temperature, humidity, and wind speed as the weather drivers. PJM has access to weather data from approximately 30 weather stations across the PJM footprint (PJM, 2008a). All NCP models used GMP and coincident peak (CP) forecasts and were modeled as zonal shares of the PJM peak. The PJM CP and zonal NCP forecasts were then published in the annual PJM Load Forecast Report (PJM, 2007d).

The PJM model uses historical data on energy usage in determining future electrical needs. Elements, such as energy efficiency measures (for example, changes to building codes, technology improvements), energy substitution (for example, use of natural gas instead of electricity), the price of alternative fuels, and saturation levels of electricity using devices, are generally reflected in this historical data. The recent historical data would reflect any changes in energy use or consumption due to these measures.

In addition to the model, PJM's RTEP process provides a mechanism for input from interested stakeholders. Input is provided through the activities of the Transmission Expansion Advisory Committee (TEAC). PJM's process is regional in scope, covering multiple transmission owners' systems and allowing for the identification of the most effective and efficient expansion plan for the region (PJM, 2008a). PJM's RTEP identifies transmission system upgrades and enhancements to preserve the reliability of the electricity grid, the very foundation for thriving competitive wholesale energy markets. Additionally, the RTEP planning horizon permits PJM to assess reliability criteria violations up to 15 years forward, conduct market efficiency scenario analyses, and perform reliability-based sensitivity analyses. New RTEP recommendations are submitted to PJM's independent Board of Managers (PJM Board) periodically throughout the year as they are identified. PJM's RTEP process includes both 5-year and 15-year dimensions. Specifically, 5-year planning enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. The 15-year horizon permits consideration of many long-lead-time transmission options. Longer lead times allow consideration of larger magnitude upgrades that more efficiently and globally address reliability issues. Typically, this can be a higher voltage upgrade that addresses many lower voltage violations simultaneously. Longer lead times also allow a plan to consider the effects of other ongoing system trends such as long-term load growth, the impacts of generation retirements, and aggregate generation development patterns across the system. This could include reliability issues posed by clusters of development based on innovative coal or nuclear technologies, renewable energy sources, or proximity to fuel sources (PJM, 2008a).

In addition, a key component of the RTEP process is to identify transmission facility siting studies that must start within the next year. The long lead times associated with the installation of transmission facilities require RTEP decisions on alternative reinforcements in order to start siting feasibility studies, followed by site selection and right-of-way acquisition. Long-term compliance with NERC Reliability Standards cannot be assured without such studies and acquisition of needed right-of-way.

Load forecasts are an important component of the PJM RTEP process. Zonal load forecasts are submitted by PJM electricity distribution members and are essential if transmission expansion studies are to yield an RTEP that continues to ensure reliable and economic system operations. Load forecasts are a fundamental component of PJM's capacity planning process and transmission expansion studies. Specifically, load forecasts support the reliability study process that yields calculations for the installed reserve margin and the DSR factor (PJM, 2008a). The PJM system load and location margin prices (LMP) reflect the configuration of the entire RTO. The PJM energy market includes the real-time energy market and the day-ahead energy market. PJM real-time load is the total hourly accounting load in real time. Figure 8.2-1 (PJM, 2008b) shows the real-time load duration curves from 2003 through 2007. A load duration curve shows the percent of hours that the load was at, or below, a given level for the year.

This section presents the historical energy and demand since 1998 and the forecasted values through 2018 for the eastern part of the PJM classic market area.

Historical demand for the entire PJM RTO area between 1997 and 2007 is presented in Table 8.2-1 (PJM, 2007d). Future unrestricted peak demand for the entire PJM RTO area and for the PJM Mid-Atlantic area for 2008 through 2018 is presented in Table 8.2-2 and Table 8.2-3 (PJM, 2007d). This approximates the ROI/primary market area. These unrestricted peak demand forecasts are based on the PJM Mid-Atlantic market area that includes the following electric companies: Atlantic Electric (AE), Baltimore Gas & Electric (BGE), Delmarva Power & Light (DPL), Jersey Central Power & Light (JCPL), Metropolitan Edison (METED), Philadelphia Electric and Gas Company (PECO), Pennsylvania Electric (PENELEC), Potomac Electric Power Company (PEPCO), PPL EU, Public Service Electric & Gas (PS), Rockland Electric Company (RECO), and UGI Utilities (UGI). It should be noted that the data in tables are for summer and winter unrestricted peak forecasts and that the data are an average of all the combined companies listed. Based on these forecast, the eastern part of the PJM classic market area will continue to be summer peaking during the next 15 years. As shown in Table 8.2-1 (PJM, 2007d), the historical energy use trend has increased over the period of 1998 to 2007. This trend of increasing electricity consumption is expected to continue, as shown in Table 8.2-2 and Table 8.2-3 (PJM, 2007d).

8.2.2 FACTORS AFFECTING POWER GROWTH AND DEMAND

This section reviews the factors that affect growth in power demand in the primary market area, the eastern part of the PJM classic market area. With the construction of the BBNPP, PPL plans to add approximately 1,600 MW of generating capacity within the eastern part of the PJM classic market area. As noted in Section 8.1.3, the eastern part of the PJM classic market area serves millions of people and includes the major U.S. load centers along the Mid-Atlantic coast of the eastern seaboard.

Most power generating facilities run in a similar fashion in the way that they operate by using some form of energy to drive a generator to produce electricity. These energy sources can include nuclear fission, steam (from coal, natural gas, oil), water, solar, and wind. Each of these technologies has different performance characteristics, entails different capital costs, and carries different operation and maintenance costs. Baseload facilities are generally in continual operation and are least expensive to run. These facilities provide electricity to meet the base demand requirements on the system and are typically natural gas/coal fired or nuclear facilities. Because they run continuously, it is desirable for baseload facilities to utilize the least expensive fuels.

Peak demand occurs when consumers in aggregate use the greatest amount of electricity. Over the course of a year, peak demand usually occurs on hot summer afternoons and cold winter evenings. Peaking power generating facilities are those facilities that can be quickly fired up to meet the peak load.

Historical summer and winter peak information for the PJM mid-Atlantic area is shown in Table 8.2-4 and Table 8.2-5 (PJM, 2005). These tables show the increase in load peaks from 1970 to 2004. The weather normalized summer peak in the overall PJM region is forecast to increase at an average rate of 1.7% through 2015. Although the expected growth rates vary in the individual utilities' geographic zones, many of the highest projected rates of annual growth are in the eastern part of the PJM classic market area. To meet this load, the PJM RTEP shows a need for reliance on western generation sources over an already congested transmission system or additional local generation resources to both ensure reliable service to customers and to obtain economical, available electricity supplies (PJM, 2007a).

A number of factors continue to reduce system reliability in the eastern part of the PJM classic market area. These factors include (PJM, 2007a):

- Load growth
- Imminent start of large power exports to New York City and Long Island over merchant transmission facilities
- Deactivation/retirement of generation resources
- Sluggish development of new generating facilities
- Continued reliance on transmission to meet load deliverability requirements and to obtain access to more economical sources of power west of the Delaware River

The following discussions focus on efforts identified to conserve and promote customer conservation of electrical energy.

As noted in Section 8.1-3, there are approximately 51 million people in the PJM region, which includes the major U.S. load centers from the western border of Illinois to the Atlantic coast. According to the 2000 U.S. Census, the population of the United States was estimated to be 281,421,906 persons. Population estimates for 2006 indicate the U.S. population is approximately 299,398,484, a 6.4% increase from the 2000 census data (US Census, 2008). Section 2.5.2.1 of this ER presents the historic and estimated growth of employment and wages in the local BBNPP area. The information presented is for the years 2000 through 2006.

Generally, trends in energy supply and demand are affected by a variety of factors that are difficult to predict. These include energy prices, national and worldwide economic growth, advances in technologies, and future public policy decisions both inside and outside of the

United States. However, energy markets change in response to factors that are predictable, such as increasing energy prices, the growing influence of developing countries on worldwide energy requirements, new legislation and regulations, changing public perceptions on energy production (for example, air pollution, greenhouse gases [GHG], alternative fuels), and the economic viability of various energy technologies (Energy Information Administration [EIA], 2008a).

According to the Energy Information Administration (EIA) branch of the U.S. Department of Energy (DOE), natural gas consumption in the electric power sector is highly responsive to market and price changes, because electricity producers can choose among different fuels on an ongoing basis. In contrast, consumption of natural gas in the residential, commercial, and industrial sectors is influenced not only by fuel prices but also by economic trends. In those sectors, natural gas consumption, which varies with natural gas prices and economic growth rates, is forecasted to increase steadily from 2006 through 2030.

High natural gas prices provide direct economic incentives for reducing natural gas consumption, whereas low prices encourage more consumption; however, the strength of the relationship depends on short- and long-term fuel substitution capabilities and equipment options within each consumption sector. Simply put, higher natural gas prices reduce demand, and higher economic growth rates increase demand. For the years 2019-2020, shortly after the beginning of commercial operation at BBNPP, natural gas consumption is expected to range from a high of approximately 24 trillion cubic feet (ft^3) (679,604 trillion cubic meters [m^3]), to a low of about 22 trillion ft^3 (622,970 trillion m^3) for the various cases studied. As one of the dominant fuel types in the PJM region, natural gas prices in 2007 are 6.4% higher than in 2006.

With faster economic growth, disposable income increases more rapidly, and consumers increase their energy purchases either by buying products that consume additional energy (such as larger homes), being less energy-efficient in using products they already own (for example, by setting thermostats higher in the winter and lower in the summer), or both. (EIA, 2008b)

According to the EIA, conventional oil production in the United States is estimated to grow from 5.1 million barrels per day in 2006 to a peak of 6.3 million barrels per day in 2018, then to decline to 5.6 million barrels per day around the year 2030. Dependence on crude oil imports in the United States is expected to decline to about 50% in 2019. There is considerable uncertainty surrounding the future of unconventional crude oil production in the United States. Environmental regulations could either preclude unconventional production or raise its cost significantly. If future U.S. laws limit and/or tax greenhouse gas emissions, the laws could lead to substantial increases in the costs of unconventional production, which emits significant volumes of carbon dioxide (CO2). Restrictions on access to water also could prove costly, especially in the arid West. In addition, environmental restrictions on land use could preclude unconventional oil production in some areas of the United States. (EIA, 2008b)

Number 2 (light) oil prices were 9.7% higher and Number 6 (heavy) oil prices were 18.4% higher in 2007 than in 2006. Since September 2007, the prices for light oil and heavy oil have been much higher than those during the corresponding period in 2006. From September to December 2007, natural gas prices were 12.3% higher, No.2 (light) oil prices were about 38% higher, and No. 6 (heavy) oil prices were about 59% higher than the corresponding fuel prices during the same months in 2006. (PJM, 2008b)

The electricity needs of the eastern part of the PJM classic market area are supplied not only by local generation, but also by significant energy transfers from the western portion of the PJM region. A significant portion of these transfers flow through transmission systems of northern West Virginia, northern Virginia, Maryland, eastern Ohio, and central southwestern Pennsylvania. The eastern part of the PJM classic market area's dependence on energy transfers from the western portion of the PJM region has been growing steadily over the past decade (PJM, 2007a).

PJM's RTEP studies show that trends in load growth and in locating new generation facilities will impose increasingly heavy loads of west to east power flows. About 9,400 MW of new generation are pending in PJM's interconnection queues with proposed commercial operation dates of 2006–2012; however, approximately 6,700 MW are proposed to be coal fired units located in the western part of the PJM area. These new resources are being constructed both to serve local load and to participate in PJM's broader energy market to the extent the transmission capability permits. (PJM, 2007a) PJM's RTEP process includes both 5-year and 15-year dimensions. Specifically, 5-year planning enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. The 15-year horizon permits consideration of many long-lead-time transmission options. Longer lead times allow consideration of larger magnitude upgrades that more efficiently and globally address reliability issues. Typically, this can be a higher voltage upgrade that addresses many lower voltage violations simultaneously. Longer lead times also allow a plan to consider the effects of other ongoing system trends such as long-term load growth, the impacts of generation retirements and aggregate generation development patterns across the system. This could include reliability issues posed by clusters of development based on innovative coal or nuclear technologies, renewable energy sources, or proximity to fuel sources (PJM, 2008a).

Since its inception in 1997, PJM's RTEP process has continued to adapt to the planning needs of RTO members and the mandates of FERC. Initially, PJM's RTEP consisted mainly of upgrades driven by load growth and generating resource interconnection requests. Today, a myriad of drivers are considered in PJM's RTEP process. The RTEP process during 2007 culminated with PJM Board approval of those system upgrades necessary to resolve reliability criteria violations identified through 2012 and beyond. Now part of PJM's RTEP, these new upgrades are integrated "on top of" existing RTEP upgrades approved between 1999 and December 31, 2006 (PJM, 2008a).

A number of state, regional, and national initiatives promote energy efficiency and the substitution of electricity for other fuels. National concern for developing adequate supplies of electric power in an environmentally sound manner has led to state consideration of renewable portfolio standards (RPS). RPS are state policies that require electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date. As of June 2007, there were 24 states, plus the District of Columbia, that had RPS policies in place. Together these states account for more than half of the electricity sales in the United States (PJM, 2008a).

Energy efficiency and DSR programs result in estimated load drops that reduce the demand for energy. There has been a substantial increase in DSR programs in recent years. These programs can include such measures as rebates or other incentives for residential customers to update inefficient appliances with Energy Star® replacements. Customers could also receive credits on their bills for allowing a utility to control, or intermittently turn off, their central air conditioning or heat pumps when wholesale electricity prices are high. In the summer of 2006, the demand response contributions of PJM totaled 2,050 MW, or approximately 1.4% of the peak load (FERC, 2007). Unlike a new power generation facility, DSR cannot be expected to provide steady capacity output over a set period. The 2008 RTEP concludes that until there is a firmly established industry standard for incorporating demand response into system planning, DSR must be conservatively evaluated to ensure that reliability is not jeopardized. DSR participants interface directly with PJM through day ahead bids, self supply, and emergency response bids (PJM, 2008a). Additional information regarding PPL EU's Demand-side Management Programs is provided in Section 9.2.

Under the Alternative Energy Portfolio Standards Act (Act 213), which became effective on February 28, 2005, Pennsylvania has committed to maintain the basics of energy production and to encourage new initiatives in DSR, energy efficiency, renewable energy, and other new technologies so it can continue as a national leader in these areas. The state also plans to continue providing assistance to low income customers to reduce energy consumption. Act 213 requires that an annually increasing percentage of electricity sold to retail customers be derived from alternative energy resources, including solar, wind, low impact hydropower, geothermal, biologically derived methane gas, fuel cells, biomass, coal mine methane, waste coal, demand side management, distributed generation, large scale hydropower, by products of wood pulping and wood manufacturing, municipal solid waste and integrated combined coal gasification technology (PPUC, 2007).

A subsequent amendment to Act 213 requires updating of PPUC's net metering regulations. Among other things, this will allow net metered customer generators to receive full retail value for all energy produced in excess of internal use. PPUC issued a Final Order governing the participation of demand side management, energy efficiency, and load management programs and technologies in the alternative energy market. PPUC also issued a Final Order governing net metering and proposed regulations concerning interconnection for customer generators using renewable resources, consistent with the goal of Act 213, and promoting onsite generation by eliminating barriers that may have previously existed regarding net metering and interconnection. Final regulations became effective on December 16, 2006. The Pennsylvania Low Income Usage Reduction Program is a statewide, utility sponsored residential usage reduction program mandated by PPUC regulations in 52 PA Code Chapter 58. The primary goal of this program is to assist low income residential customers to reduce energy bills through usage reduction (energy conservation) and, as a result, to make bills more affordable (PPUC, 2007).

The Clear Skies Act of 2003 (Clear Skies Act) amends Title IV of the Clean Air Act to establish new cap and trade programs requiring reductions of sulfur dioxide, nitrogen oxides, and mercury emissions from power generating facilities, and it amends Title I of the Clean Air Act to provide an alternative regulatory classification for units subject to the cap and trade programs. Under this Act, retail prices are projected to increase by approximately 2.1% to 4.2% between 2005 and 2020. It is anticipated that the health benefits in Pennsylvania would total approximately $1.8 to $9.3 billion and include approximately 700 to 1,200 fewer premature deaths and 1,800 fewer hospitalizations and emergency room visits for asthma (U.S. Environmental Protection Agency [USEPA], 2003).

As part of Pennsylvania's renewable and sustainable energy efforts, four funds were created as a result of the restructuring plans of five electric companies. The funds are designed to promote the development of sustainable and renewable energy programs and clean air technologies on both a regional and statewide basis. The funds have provided more than $20 million in loans and $1.8 million in grants to over 100 projects. The Statewide Sustainable Energy Board was formed in 1999 to enhance communications among the four funds and state agencies. The board includes representatives from PPUC, the Pennsylvania Department of Environmental Protection (PADEP), the Department of Community and Economic

Development, the Office of Consumer Advocate, the Pennsylvania Environmental Council, and each regional board (PPUC, 2007).

The four renewable and sustainable energy funds include:

- West Penn Power (Docket No.: R 00973981)
- METED (Docket No. R 00974008) and PECO (Docket No. R 00974009)
- PPL Sustainable Energy Fund of Central/Eastern Pennsylvania (Docket No. R 00973954)
- PECO Energy (Docket No. R 00973953)

As noted in Section 8.0, the Commonwealth of Pennsylvania deregulated electric utilities in 1996. Now PPUC looks to regional entities, such as PJM, for the management of the electric system. PJM makes us of market forces to encourage independent owners to build the needed facilities. However, if the market does not appear to be providing sufficient incentive to ensure continuing system reliability, PJM then steps in to assist with directing when and where new power generation or transmission facilities might be needed (PPUC, 2007).

The price for retail electricity in Pennsylvania is regulated by PPUC. In 2006, the average retail price for electricity in Pennsylvania was 8.68 cents per kWh, which ranked as the eighteenth highest in the United States (EIA, 2007). The average price of electricity in Pennsylvania from 1990 to 2006 is shown in Figure 8.2-2 (EIA, 2007). Electric distribution companies such as PPL EU are required to submit annual reports to PPUC indicating a proposed price structure. PPL EUs currently effective tariff includes the rules and rates schedules for electric service.

In 2006, electricity in New Jersey had an average retail price of 11.88 cents per kWh, which was the ninth highest in the United States). Delaware had an average retail price of 10.13 cents per kWh (fifteenth highest); while Maryland had an average retail price of 9.95 cents per kWh (sixteenth highest); and Virginia had an average retail price of 6.86 cents per kWh (thirty ninth highest). Figure 8.2-3 through Figure 8.2-6 show the average price of electricity in New Jersey, Delaware, Maryland, and Virginia from 1990 to 2006 (EIA, 2007).

Additionally, the other states within the ROI/primary market area (that is, New Jersey, Delaware, Maryland, and Virginia) have enacted policies and requirements to regulate GHG and renewable energy and conservation measures. Discussions of these state policies and requirements are discussed in detail in Section 9.1 and Section 9.2.

PJM uses a Reliability Pricing Model to provide a long term pricing signal for capacity resources and the obligations of each load serving entity (LSE) that is consistent with the PJM RTEP process.

8.2.3 REFERENCES

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Table 8.2-1—PJM RTO Historic Unrestricted Peak (MW)

	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Summer	114,996	121,655	114,178	131,116	130,360	126,332	120,235	134,219	145,951	141,383
	1997/98	**1998/99**	**1999/2000**	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**
Winter	88,970	99,982	102,359	101,717	97,294	112,755	106,760	114,061	110,415	118,800

Note:
MW = megawatts

Table 8.2-2—PJM Mid-Atlantic Summer Unrestricted Peak Forecast (MW)

	2008	2009	2010	2012	2012	2013	2014	2015	2016	2017	2018
Mid-Atlantic	60,735	61,822	62,885	63,920	64,748	65,850	66,818	67,741	68,679	69,599	70,472
Increase		1.8%	1.7%	1.6%	1.3%	1.7%	1.5%	1.4%	1.4%	1.3%	1.3%
RTO	137,948	140,407	142,884	145,061	147,183	149,495	151,675	153,933	156,030	158,176	160,107
		1.8%	1.8%	1.5%	1.5%	1.6%	1.5%	1.5%	1.4%	1.4%	1.2%

Note:
MW = megawatts

Table 8.2-3—PJM Mid-Atlantic Winter Unrestricted Peak Forecast (MW)

	2007/08	2008/09	2009/10	2010/11	2012/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Mid-Atlantic	46,651	47,101	47,778	48,413	48,997	49,529	50,023	50,582	51,155	51,776	52,310
Increase		1.8%	1.7%	1.6%	1.3%	1.7%	1.5%	1.4%	1.4%	1.3%	1.3%
RTO	113,565	114,728	116,408	117,871	119,240	120,569	121,685	123,165	124,545	125,996	127,250
		1.0%	1.5%	1.3%	1.2%	1.1%	0.9%	1.2%	1.1%	1.2%	1.0%

Note:
MW = megawatts

Table 8.2-4—PJM Mid-Atlantic Historical Summer Peaks (MW)

Normalized		Normalized	Normalized	Metered	Peak	
Year	Base	Cooling	Total	Peak	Date/Time	
1970	17,358	7,236	24,594	23,838	7/28/1970	15:00
1971	18,110	7,869	25,979	25,529	7/1/1971	14:00
1972	19,275	8,682	27,957	27,852	7/20/1972	14:00
1973	20,261	9,341	29,602	30,993	8/30/1973	15:00
1974	19,962	9,531	29,493	29,065	7/10/1974	15:00
1975	19,965	9,335	29,300	28,969	8/1/1975	16:00
1976	20,729	9,733	30,462	29,264	8/26/1976	16:00
1977	21,085	9,697	30,782	32,180	7/21/1977	16:00
1978	21,668	9,996	31,664	31,686	8/16/1978	15:00
1979	22,065	10,608	32,673	31,654	8/2/1979	14:00
1980	21,933	10,900	32,833	34,420	7/21/1980	14:00
1981	22,209	11,334	33,543	33,528	7/9/1981	16:00
1982	22,051	10,276	32,327	33,741	7/19/1982	15:00
1983	22,510	12,276	34,786	34,678	9/6/1983	17:00
1984	23,288	13,024	36,312	35,337	6/13/1984	17:00
1985	24,076	12,891	36,967	37,018	8/15/1985	15:00
1986	24,501	13,004	37,505	37,527	7/7/1986	17:00
1987	25,318	14,232	39,550	40,526	7/24/1987	15:00
1988	26,381	14,679	41,060	43,073	8/15/1988	17:00
1989	26,545	15,245	41,790	41,556	8/4/1989	16:00
1990	26,875	15,701	42,576	42,544	7/5/1990	14:00
1991	26,822	16,941	43,763	45,870	7/23/1991	16:00
1992	27,114	16,138	43,252	43,622	7/14/1992	17:00
1993	27,598	16,976	44,574	46,429	7/8/1993	17:00
1994	27,613	17,437	45,050	45,992	7/8/1994	14:00
1995	28,072	18,998	47,070	18,524	8/2/1995	17:00
1996	28,523	17,967	46,490	44,302	8/23/1996	17:00
1997	28,646	19,854	48,500	49,406	7/15/1997	17:00
1998	29,360	20,250	49,610	48,397	7/22/1998	17:00
1999	29,190	21,320	50,510	51,700	7/6/1999	14:00
2000	31,120	21,230	52,350	49,430	8/9/2000	17:00
2001	30,550	23,690	54,240	54,072	8/9/2001	15:00
2002	31,390	24,580	55,970	55,569	8/14/2002	16:00
2003	31,550	24,180	55,730	53,566	8/22/2003	16:00
2004	31,340	25,101	56,441	52,049	8/20/2004	16:00

Note:
MW = megawatts
Source: PJM 2005

Table 8.2-5—PJM Mid-Atlantic Historical Winter Peaks (MW)

Normalized		Normalized	Normalized			
Base		Heating	Total	Metered	Peak	
Year	(Evening)	(Evening)	(Evening)	Peak	Date/Time	
1969/70	16,878	3,060	19,938	20,334	1/21/1970	19:00
1970/71	17,976	3,293	21,269	21,730	2/1/1971	19:00
1971/72	18,488	3,816	22,304	21,787	2/8/1972	19:00
1972/73	19,614	4,514	24,128	24,153	1/8/1973	18:00
1973/74	18,580	4,870	23,450	22,540	2/5/1974	11:00
1974/75	19,475	4,762	24,237	23,569	1/14/1975	18:00
1975/76	20,295	5,307	25,602	25,498	1/22/1976	19:00
1976/77	20,260	6,363	26,623	27,073	1/17/1977	19:00
1977/78	21,142	6,144	27,286	27,967	1/10/1978	18:00
1978/79	21,887	6,589	28,476	28,413	2/13/1979	19:00
1979/80	22,052	6,362	28,414	27,621	1/31/1980	19:00
1980/81	21,720	7,639	29,359	29,625	1/21/1981	19:00
1981/82	22,036	6,930	28,966	30,621	1/11/1982	11:00
1982/83	21,929	6,448	28,377	28,092	1/19/1983	19:00
1983/84	23,020	6,874	29,894	29,658	1/20/1984	10:00
1984/85	23,485	7,998	31,483	33,278	1/21/1985	19:00
1985/86	23,980	7,821	31,801	31,621	1/28/1986	19:00
1986/87	24,530	7,529	32,059	32,537	1/28/1987	9:00
1987/88	26,012	9,281	35,293	35,738	1/5/1988	19:00
1988/89	27,336	8,654	35,990	36,326	12/12/1988	19:00
1989/90	28,219	9,873	38,092	38,100	12/22/1989	9:00
1990/91	28,028	9,180	37,208	36,505	1/12/1991	19:00
1991/92	27,655	10,141	37,806	37,927	1/16/1992	19:00
1992/93	28,067	10,634	38,701	37,860	2/2/1993	9:00
1993/94	27,999	10,898	38,897	41,351	1/18/1994	19:00
1994/95	28,474	11,806	40,280	40,598	2/6/1995	19:00
1995/96	29,222	10,718	39,940	40,746	2/5/1996	19:00
1996/97	29,616	11,284	40,900	40,468	1/17/1997	19:00
1997/98	29,990	11,510	41,500	37,158	12/22/1997	18:00
1998/99	30,680	10,410	41,090	40,417	1/14/1999	18:00
1999/00	31,560	11,020	42,580	42,395	1/27/2000	19:00
2000/01	32,040	11,840	43,880	41,379	12/20/2000	19:00
2001/02	32,700	11,400	44,100	39,458	1/2/2002	19:00
2002/03	32,720	11,420	44,140	46,239	1/23/2003	19:00
2003/04	33,950	10,290	44,240	45,625	1/26/2004	19:00

Note:
MW = megawatts
Source: PJM 2005

Figure 8.2-1—PJM Real - Time Load Duration Curve 2003-2007

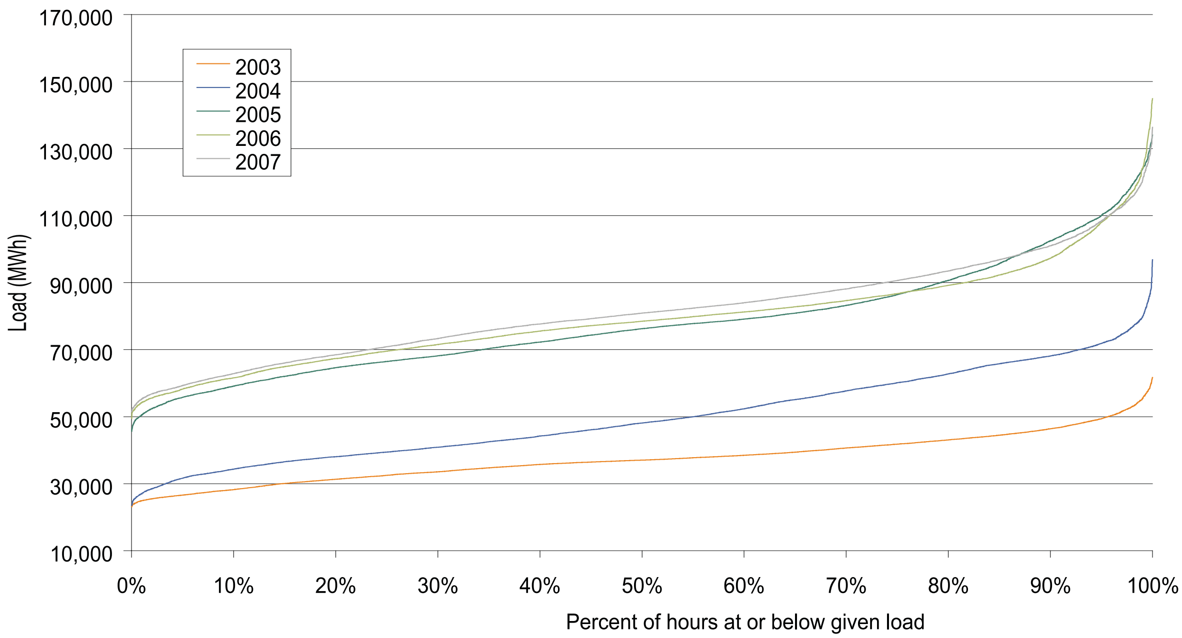


Figure 8.2-2—1990-2006 Average Electric Price in Pennsylvania

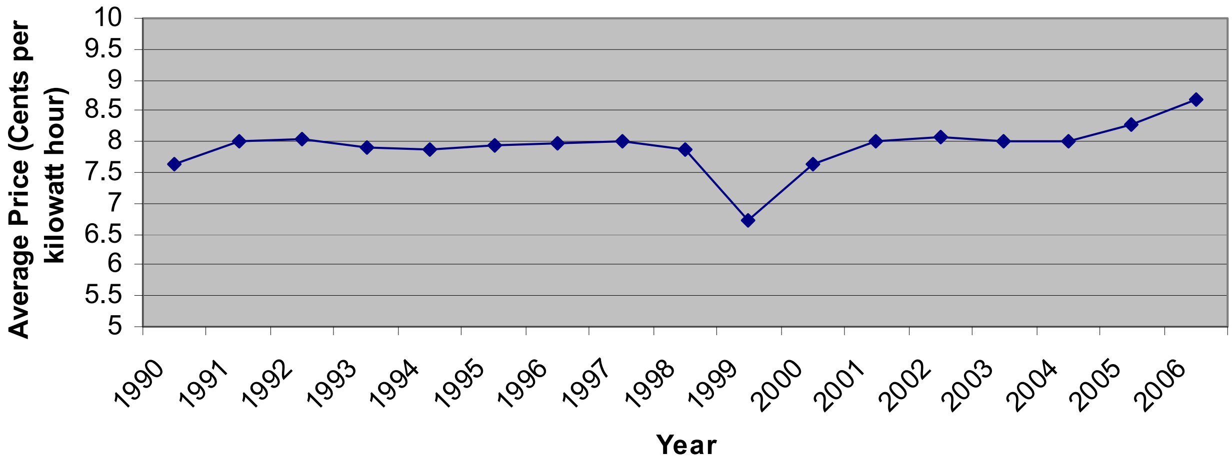


Figure 8.2-3—1990-2006 Average Electric Price in New Jersey

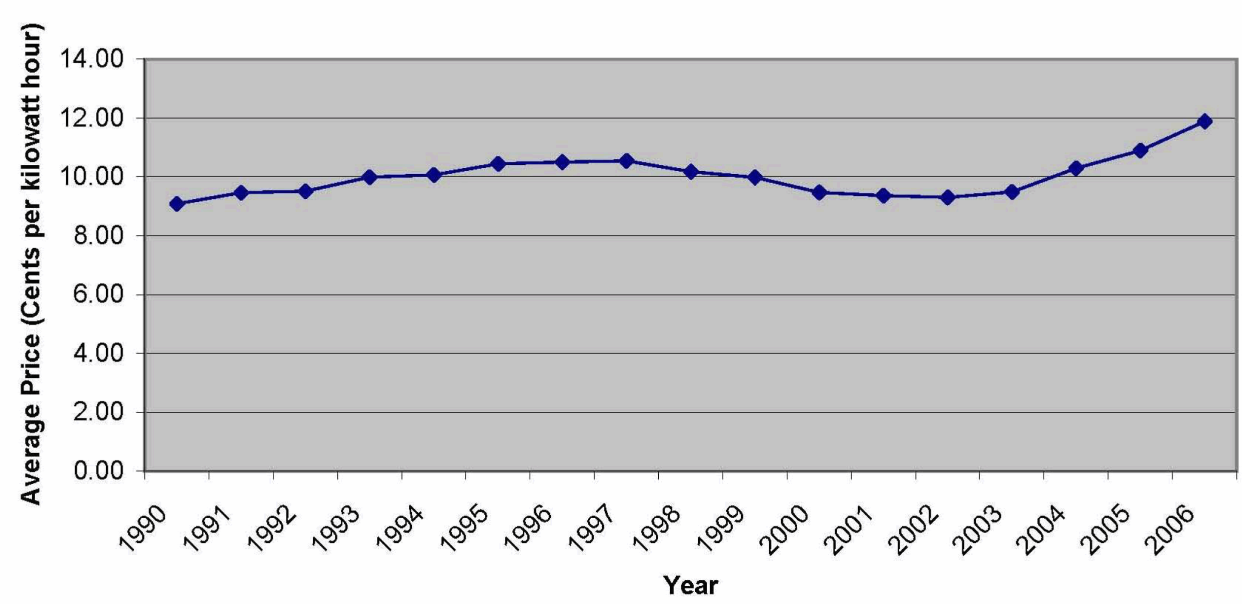


Figure 8.2-4—1990-2006 Average Electric Price in Delaware

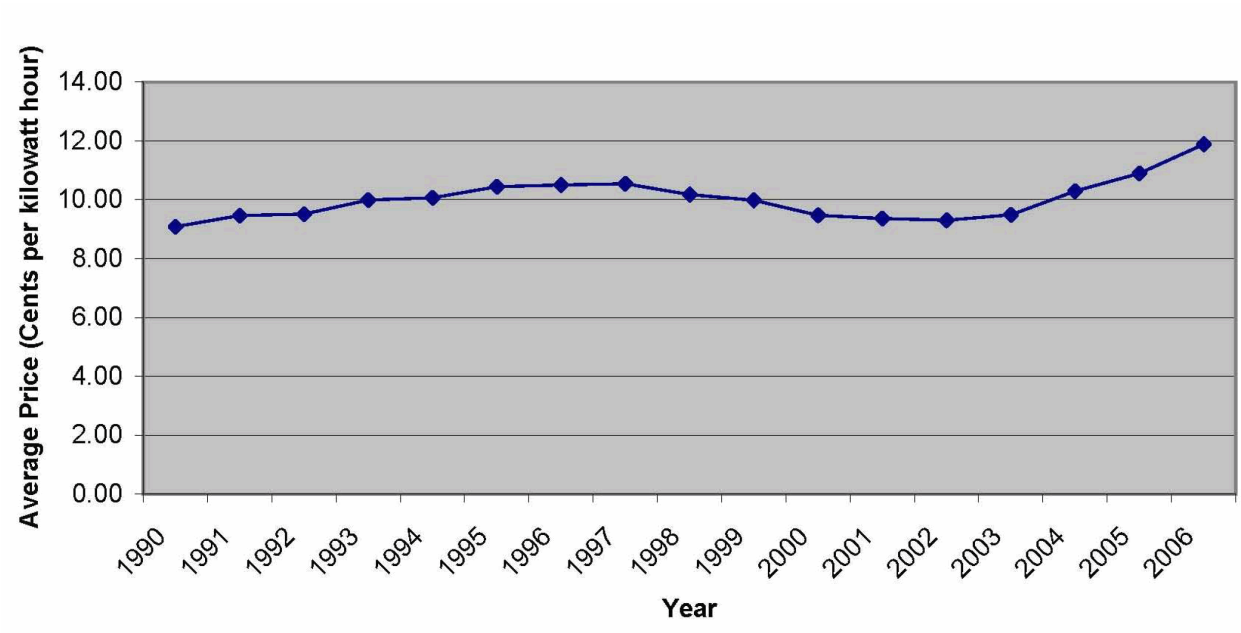


Figure 8.2-5—1990-2006 Average Electric Price in Maryland

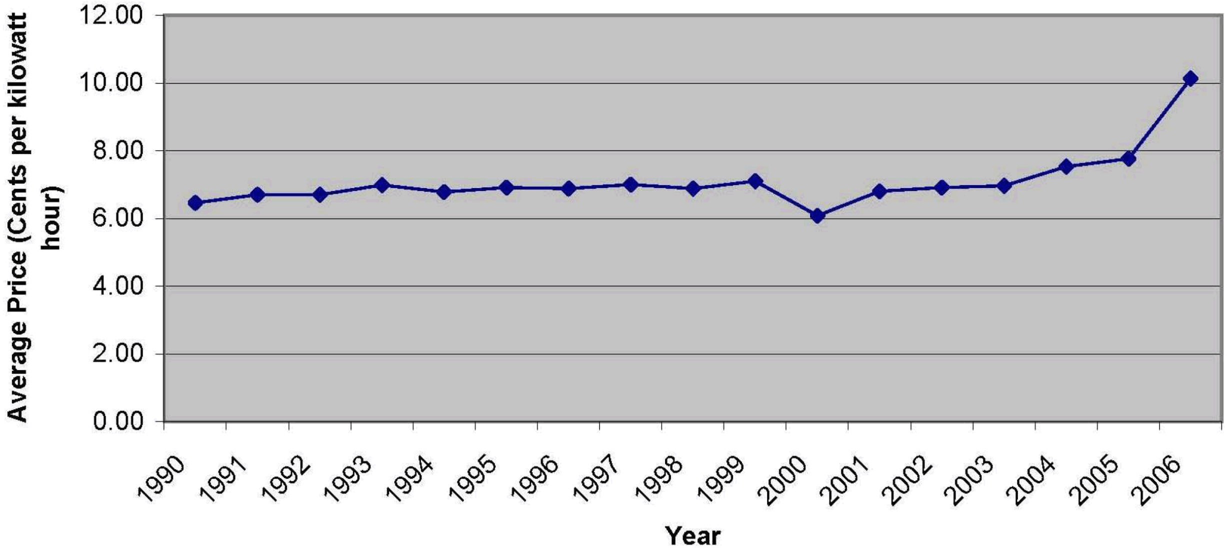
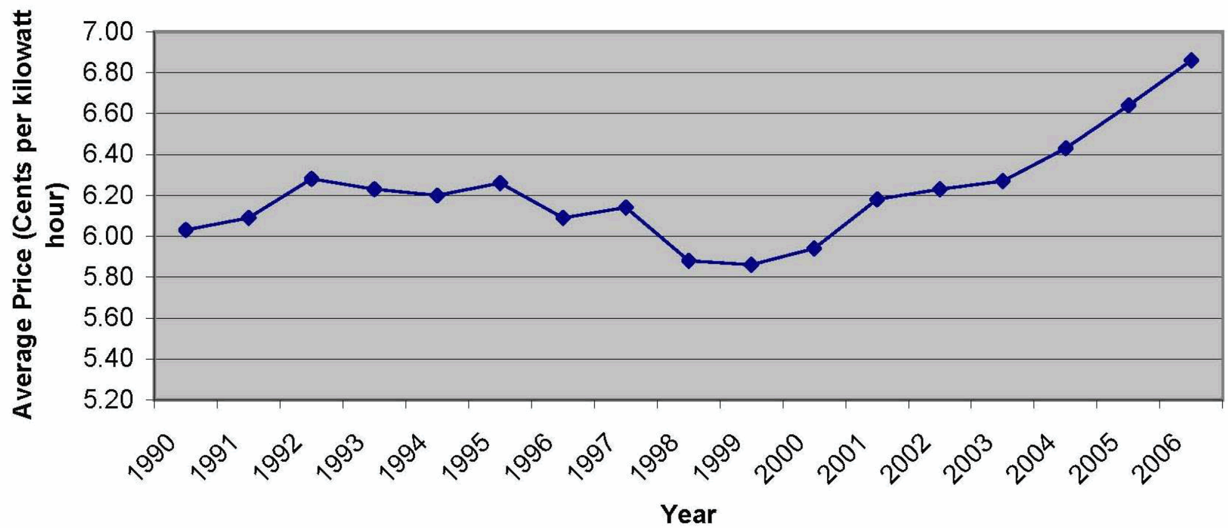


Figure 8.2-6—1990-2006 Average Electric Price in Virginia



8.3 POWER SUPPLY

PJM published information regarding the annual state of the market in its "2007 PJM State of the Market Report" (PJM, 2008a). This report contains PJM's most recent assessment of the state of competition in each market operated by PJM, identifies specific market issues, and recommends potential enhancements to improve the competitiveness and efficiency of the markets. Additionally, PJM published information regarding generating unit ratings in its "2007 PJM EIA 411 Report" (PJM, 2007a). This report contains PJM's most recent assessment of each utility system's installed capacity. PJM uses the term "rating" synonymously with installed capacity, and these values are the basis for the following regional capability analysis:

- **PJM Installed Capacity by Fuel Type.** At the end of 2007, PJM's installed capacity was 163,498 MW. Of the total installed capacity, 40.5% was coal, 29.1% was natural gas, 18.9% was nuclear, 6.5% was oil, 4.5% was hydroelectric, and 0.4% was solid waste. At the beginning of the new planning year on June 1, 2007, installed capacity increased by about 1,623 MW to 163,659 MW, a 1% increase in total PJM capacity over the May 31 level. Table 8.3-1 (PJM, 2008a) provides additional information about PJM's installed capacity.

- **Generation Fuel Mix.** During 2007, coal provided 55.3%, nuclear 33.9%, natural gas 7.7%, oil 0.5%, hydroelectric 1.7%, solid waste 0.7%, and wind 0.2% of total generation. Table 8.3-2 (PJM, 2008a) presents detailed information about generation fuel mix.

- **Planned Generation.** If current trends continue, it is expected that units burning natural gas will replace older steam units in the east and the result has potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure. As noted in Section 8.2.2, PJM has proposed over 9,400 MW of new generation for commercial operation dates of 2006–2012, with most of the new generation units proposed to be baseload coal fired units located in the western part of the PJM area.

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects the market's perception of the incentives provided by the combination of revenues from the PJM energy, capacity, and ancillary service markets. At the end of 2007, 74,006 MW of capacity were in generation request queues for construction through 2016, compared to an average installed capacity of approximately 163,000 MW in 2007 and a year end installed capacity of 163,498 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000. Table 8.3-3 (PJM, 2008b) provides the total capacity additions from 2000 through 2007.

One of PJM's primary roles is the oversight of the reliability planning process (PJM, 2008b). PJM manages incremental generation capacity development through the Generation Interconnection Queue, which is part of a larger RTEP. Developers wishing to provide new incremental generation capacity must file an interconnection request and enter into PJM's queue based, three study interconnection process, which offers developers the flexibility to consider and explore their respective generation interconnection business opportunities. While a developer can withdraw a project from the Generation Interconnection Queue at any point, the process is structured such that each step imposes its own increasing financial obligations on the developer (PJM, 2008c). While not all projects in the Generation Interconnection Queue are expected to be built, the Generation Interconnection Queue does provide an authoritative source for future generation investment trends in the PJM RTO. All interconnection requests that are received within each 6-month period ending on January 31 and July 31 of each year collectively comprise an Interconnection Queue. Effective February 1, 2008, interconnection queues comprise all such requests received on a 3-month basis, for the periods ending January 31, April 30, July 31, and October 31 (PJM, 2008b).

Table 8.3-4 (PJM, 2008b) shows the queued capacity by fuel type in Pennsylvania, and Table 8.3-5 (PJM, 2008b) shows the queued generation interconnection requests in the ROI/primary market area. A more detailed examination of PJM queue data reveals some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west. The geographic distribution of units by fuel type in the queues, when combined with data on unit age, suggests that reliance on natural gas as a fuel in the east will increase (PJM, 2008b). Heavy reliance on natural gas is a concern due to future congestion and uncertainties in supply and infrastructure as noted above. Other alternatives, such as nuclear energy generation, could be explored as an option that would not have these concerns.

Within the ROI/primary market area, planned projects representing potential nuclear baseload capacity are captured in the PJM Generation Interconnection Request queues, as detailed in Table 8.3-5. Of these, upgrades to existing facilities (Salem, Hope Creek, Susquehanna, Peach Bottom, TMI) represent a total of 688 MWe, with all but one project targeted to complete prior to 2010. In addition to BBNPP, the Calvert Cliffs Nuclear Power Plant 3 project (1,640 MWe) is the other new plant planned within the ROI, which would have comparable access to the primary market area as the proposed BBNPP. Inclusion in the PJM Generation Interconnection Request queues incoporates these proposed generation additions into PJM's planning processes, including RTEP and their reserve margin requirements studies.

Table 8.3-6 (PJM, 2008b) presents the RTEP projects under construction or active as of December 31, 2007, by unit type and control zone. Most (93%) of the steam projects (predominantly coal) and most of the wind projects (94%) are outside the Eastern Mid Atlantic Area Council (EMAAC) and Southwestern Mid Atlantic Area Council (SWMAAC) location deliverability areas (LDA). Most (60%) of the combined cycle (CC) projects are in EMAAC and SWMAAC. Wind projects account for approximately 25,211 MW of capacity.

Table 8.3-7 (PJM, 2008b) lists existing generators by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity are distributed across control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (PJM, 2008b) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas fired CC and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely.

As noted in Section 8.2.1, the scope of 15-year forecast model planning encompasses sensitivity studies that examine the long-term reliability impacts of uncertainty with respect to assumptions about economic growth, the extent of loop flows within PJM and the assumptions about generation resources (PJM, 2008b).

- Results of studies addressing load forecasting economic growth uncertainty have the potential to advance RTEP system upgrades in the 6- to 10-year timeframe.

- In July 2006, the PJM Planning Committee approved a circulation model to be deployed in sensitivity studies analyzing forecasting model reliability. The goal of developing such a model has the benefit of more closely aligning planning studies to reflect real-time system conditions. The circulation model is applied to an RTEP base case, and any new overloads due to the PJM generator deliverability test are identified and system upgrades included in the RTEP.

- In order to complete original 15-year baseline analyses, PJM can increase existing generation (including units with executed interconnection service agreements [ISAs]) above actual capabilities for studies in the 6- to 15-year timeframe. This can permit the availability of sufficient generation to meet requirements for load (including line losses and firm interchange). Sensitivity studies can also model generation that has received an impact study to determine the impact on previously identified baseline overloads.

Technologies for power generation are often categorized as baseload, intermediate, and peaking capacity and firm and non-firm sales. Baseload capacity is generally coal fired or nuclear, is the most expensive to build, takes the most time to start up and shut down, and is the least expensive to operate for extended periods. For purposes of this analysis, baseload capacity is defined as the average peak load on non-holiday weekdays with no heating or cooling load. Baseload is insensitive to weather to include units with a capacity factor of 65% or greater (PJM, 2008c). Peaking units are generally gas fired turbines and are the least expensive to build, can be quickly started or stopped, and are the most expensive to operate for extended periods. The characteristics of intermediate capacity fall between baseload and peaking capacity.

PJM uses concentration ratios as part of the reliability planning analysis for assessment of energy market capacity needs. Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios also indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. An analysis of the PJM Energy Market indicates moderate market concentration overall and indicates moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments (PJM, 2008a).

During peak demand periods when consumers demand more electricity, the generating units with higher variable fuel costs (typically oil or natural gas fired) and the operational capability to quickly start are called upon by PJM RTO to meet the peak load. "Peaking capacity," while expensive to operate, is relatively less expensive to construct.

Additionally, PJM power generation assesses market sales through firm market sales and non-firm market sales. Simply stated, firm sales are intended to be available at all times during a period and covered by an agreement. Non-firm sales are commitments of power availability having limited or no assured availability.

Firm transmission service is considered the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. Similarly, PJM-contracted transmission providers can offer high-quality firm transmission service to customers without requiring the filing of a rate schedule. Firm transmission service only includes firm point-to-point service, network designated transmission service and grandfather agreements deemed firm by the transmission provider as posted on OASIS. Firm point-to-point transmission service is transmission service that is reserved and/or scheduled between specified points of receipt and delivery. Firm transmission service is transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the PJM Office of Interconnection.

Non-firm market flows are considered as non-firm use of the transmission system for congestion management purposes, are curtailed on a proportional basis with other non-firm uses during periods of non-firm curtailments, and are equivalent to non-firm transmission service. Non-firm point-to-point transmission service is point-to-point transmission service under the OATT that is reserved and/or scheduled on an as-available basis and is subject to curtailment or interruption. Non-firm point-to-point transmission service is available on a stand-alone basis for periods ranging from one hour to one month. (PJM, 2008d)

PJM's RTEP process incorporates consideration of long-term firm (LTF) transmission service requests (TSR). These TSRs include requests for point-to-point transmission service for a period of 1 year or more. From a planning perspective, long-term firm transmission service requests (LTFTSR) are treated in a manner similar to that of a generator interconnection request and can similarly drive the need for transmission upgrades to ensure continued system reliability. Once identified transmission system upgrades requirements are in place, the TSR can be awarded. To date, only one such request has been received that has opted to pursue a TSR award that has required transmission upgrades – a First Energy long-term firm point-to-point TSR request for 1,000 MW with 500 MW designated for delivery from the Midwest Independent System Operator (MISO) to METED and 500 MW designated for delivery from MISO to PENELEC. LTFTSR received to date are listed in Table 8.3-8 (PJM, 2008e)

Revenues from annual financial transmission right (FTR) auctions are allocated annually to firm transmission service customers by way of long-term auction revenue rights (ARR) entitlements. PJM's RTEP process incorporates steps to determine the transmission system enhancements required to maintain the 10-year feasibility of Stage 1A ARRs. If a simultaneous feasibility test (SFT) violation occurs in any year of the analysis, then a transmission upgrade or acceleration of a planned upgrade to resolve the violation is identified by PJM and such upgrade is recommended for incorporation into the PJM RTEP. ARRs queued for a planning study to date are listed in Table 8.3-9 (PJM, 2008e).

There are a number of planned retirements in the PJM market area. These known retirements are listed in Table 8.3-10 (PJM, 2008f). Generator deactivations alter power flows that often yield transmission line overloads. From an RTEP perspective, generation retirements announced over the last three years coupled with steady load growth and sluggish generation additions have led to the emergence of reliability criteria violations in many areas of PJM. Under the provisions of the PJM OATT, generator owners can request deactivation of a unit with 90 days' notice, which allows PJM time to assess reliability effects of the proposed retirements and make compensation plans to keep units needed to maintain the reliability of the transmission system online. Under a FERC order, the impacts of the planned deactivations - with respect to identifying required network upgrades and the allocation of costs for such upgrades - are "queued" based on the generation owner's withdrawal notification date for future assessment by PJM of the full extent of the impacts. Following assessment of the impacts, PJM makes the necessary RTEP process changes to ensure full compliance with FERC requirements. However, in accordance with a FERC order, PJM cannot compel generator owners to keep units planned for retirement in service (PJM, 2008e).

The measures of reliability generally are divided between probabilistic measures (loss of load probability, frequency, and duration of outages) and non-probabilistic measures (reserve margin and capacity margin). The commonly used "capacity margin" is the ratio of reserve capacity to actual capacity.

Reserve margin is the supply capacity maintained in excess of anticipated demand. This excess helps maintain reliable load regardless of unanticipated interruptions in supply (generation or transmission capacity) or increases in demand. Reserve margins are typically established to maintain the risk of unscheduled interruptions to 1 day in 10 years. Historical information on reserve margins in the PJM RTO is presented in Table 8.3-12 (PJM, 2007b).

The reserve margin, or reserve capacity, is a measure of unused available capacity over and above the capacity needed to meet normal peak demand levels. For a power generator, it refers to the amount of capacity it can generate above what is normally required. For a transmission company, it refers to the capacity of the transmission infrastructure to handle additional energy transport if demand levels rise beyond expected peak levels. Producers and transmission facilities are usually required to maintain a constant reserve margin of 10 to 20% of normal capacity by regulatory authorities. This provides an assurance against breakdowns in part of the system or sudden increases in energy demand (Edison Electric Institute, 2001). (PJM, 2008a). As of August 28 2008, PJM forecasted summer peak reserve margins of 19.7% for the planning year 2012/2013 (PJM, 2008c).

Electric utilities forecast demand to increase over the next 10 years by 19% (141,000 MW) in the United States and 13% (9,500 MW) in Canada, but project committed resources to increase by only 6% (57,000 MW) in the United States and by 9% (9,000 MW) in Canada. Given the short lead time for developing some types of generation, this difference could be offset by assignment or development of capacity that has not yet been committed or announced.

Today, over 50,000 MW of uncommitted resources exist NERC-wide that either do not have firm contracts or a legal or regulatory requirement to serve load, lack firm transmission service or a transmission study to determine availability for delivery, are designated or classified as energy only resources, or are in mothballed status because of economic considerations.

Over the next 10 years, uncommitted resources will more than double with the inclusion of generation currently under construction or in the planning stage, which is not yet under contract to serve load. In many cases, these uncommitted resources represent a viable source of incremental resources that can be used to meet minimum regional target levels.

In its report, NERC recognized several issues that need to be addressed regarding resource adequacy (PPUC, 2007):

- Electric utilities need to commit to add sufficient supply side or demand side resources, through either markets, bilateral contracts, or self supply, to meet minimum regional target levels.

- Electric utilities, with support from state, federal, and provincial government agencies, need to actively pursue effective and efficient demand response programs.

- NERC, in conjunction with regional reliability organizations, electric utilities, resource planning authorities, and resource providers, will address the issue of "uncommitted resources" by establishing more specific criteria for counting resources toward supply requirements.

- NERC will expedite the development of its new reliability standard on resource adequacy assessment that will establish parameters for taking into account various factors, such as: fuel deliverability; energy limited resources; supply/demand uncertainties; environmental requirements; transmission emergency import constraints and objectives; capability to share generation reserves to maintain reliability, etc.

PJM coordinates with its member companies to meet the load requirements of the region. PJM's members also use bilateral contracts and the spot energy market to secure power to meet the electric load of about 51 million people over an area of 164,260 mi^2 (425,431 km^2). In order to reliably meet its load requirement, PJM must monitor and assess over 56,000 mi (14,503 km) of transmission lines for congestion concerns or physical capability problems. There are more than 450 members of PJM.

The PJM reliability standards are the same as the standards for the Mid Atlantic Area Council (MAAC) region and the newly formed RFC region. Sufficient generating capacity must be installed to ensure that the probability of system load exceeding available capacity is no greater than 1 day in 10 years. Currently, a reserve margin of 15% of the net internal demand is considered adequate.

PJM also evaluates the adequacy of the planned transmission system's ability to meet customer energy and demand requirements in light of reasonably expected outages to system facilities. Generation plans, transmission plans, and load forecasts provide the basis for system models upon which the analysis is performed. The PJM OATT contains certain technical requirements and standards applicable to generation interconnections with transmission providers. Table 8.3-11 (PPUC, 2007) presents the distribution of energy resources used to generate electricity in the PJM region.

At the end of 2006, approximately 46,372 MW of capacity were in PJM's generation request queues for construction, increasing supply by over 28%. It is not likely that all of the generation in the queues will be built.

On May 4, 2004, the PPUC approved regulations to tighten reliability standards and reporting requirements for electric utilities. The new standards are geared toward ensuring that electric utility performance with regard to the number and duration of power outages does not decline and toward making it easier for regulators to spot areas where service may be slipping (PPUC, 2007).

As part of the PJM ability to ensure electrical reliability, it has established interchange agreements with surrounding RTOs/ISOs. These agreements ensure PJM and other RTOs/ISOs to have equal ability to service their regional firm loads. PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials. The external regions include both market and non-market control areas.

Transactions between PJM and multiple RTOs/ISOs in the Eastern Interconnection are part of a single energy market. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and ARRs in PJM), and transparent, least-cost, security-constrained economic dispatch for all available generation.

The PJM Market Monitoring Unit (MMU) analyzes transactions between PJM and neighboring control areas, including evolving transaction patterns and economics issues. PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, but that is no longer the case. PJM continues to be a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 42% of the total real-time net exports and two interfaces accounted for 95% of the real-time net import volume. Three interfaces accounted for 54% of the total day-ahead net exports and three interfaces accounted for 98% of the day-ahead net import volume. (PJM, 2008a)

There is a substantial level of transactions between PJM and the contiguous control areas. The transactions with other market areas are largely driven by the market fundamentals within each area and between market areas and are discussed below: (PJM, 2008a)

- On May 22, 2007, the joint operating agreement (JOA) between PJM and the NYISO became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. This agreement does not include provisions for market-based congestion management or other market-to-market activity.

- The JOA between the MISO and PJM continued in 2007 as in 2006, in its second, and final, phase of implementation, including market-to-market activity and coordinated, market-based congestion management within and between both markets.

- The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, between PJM, the MISO and TVA, provides for comprehensive reliability management among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA.

- On September 9, 2005, FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005.

- On May 23, 2007, PJM and Virginia and Carolinas Area (VACAR) South entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

In addition to concerns of long term supply assurance, reliance on power imported from other states increases demand on west to east transmission capabilities, resulting in heightened vulnerability to transmission related interruptions. In fact, the U.S. Department of Energy (DOE) has identified the Atlantic coastal area from Metropolitan New York southward through northern Virginia as one of two Critical Congestion Areas within the United States, stating the following (DOE, 2006):

> *The area from greater New York City south along the coast to northern Virginia is one continuous congestion area, covering part or all of the states of New York, Pennsylvania, New Jersey, Delaware, Maryland, Virginia, and the District of Columbia. This area requires billion of dollars of investment in new transmission, generation, and demand side resources over the next decade to protect grid reliability and ensure the area's economic vitality. Planning for the siting, financing, and construction of these facilities is urgent.*

According to the study, the cost of congestion varies in real time according to: (1) changes in the levels and patterns of customer demand (including responses to price changes), (2) the availability of output from various generation sources, (3) the cost of generation fuels, and (4) the availability of transmission capacity. PJM was among the first to seek early designation of two transmission corridors designed to address congestion problems, which have been included in the DOE study (PJM, 2006a). PJM's two proposed corridors are the Allegheny Mountain Corridor, extending from the West Virginia panhandle region southeastward and serving populations in the Baltimore and Washington areas, and the Delaware River Corridor, extending from the West Virginia region eastward and serving population centers around Philadelphia, New Jersey, and Delaware. Congestion costs resulting from constraints in the Allegheny Mountain Corridor totaled $747 million in 2005, with another $464 million on the Delaware River Corridor that year.

The study also notes that, while the eastern portion of PJM experiences continuing load growth, it also faces power plant retirements and limited new generation projects. Transmission constraints are causing significant congestion in both the western and eastern portions of PJM because the grid cannot accommodate delivering the available lower cost Midwest coal and nuclear fueled generation to the East (DOE, 2006).

Further, DOE was given the authority of National Interest Electric Transmission Corridors (NIETC) by Congress through the Energy Policy Act of 2005 (EPACT) to conduct national electric transmission congestion studies and, if warranted, to designate NIETCs. Designation as an NIETC is a federal recognition that an area meets certain criteria that establish a need that may be resolved by generation, demand side resources or additional transmission capability and remains in effect for 12 years. The designation gives FERC authority to approve new power lines in the corridors. This designation also recognizes that proposed transmission lines in the area serve a national and local interest, and it enables the coordination of federal authorities, if needed. If a utility does not receive state approval to build a proposed transmission project in an NIETC within a year, the utility can apply to FERC to authorize the line and give the utility eminent domain authority (PPUC, 2008).

On October 2, 2007, DOE made final designations of NIETCs in different parts of the United States, including the Mid Atlantic area. The Mid Atlantic NIETC includes 52 of Pennsylvania's 67 counties and portions of New York, Virginia, West Virginia, Ohio, Maryland, Delaware, and the District of Columbia. The intent of this NIETC designation is to alleviate transmission congestion in critical congestion areas in the Mid Atlantic Region (PPUC, 2008).

As previously noted, PJM was the first RTO to file for corridor designations with DOE. In 2006, PJM called for the designation of three NIETCs: the Allegheny Mountain Corridor, the Delaware River Corridor, and the Mid Atlantic Corridor. One NIETC in particular, the Allegheny Mountain Corridor, is the stated priority and is urgently needed to avoid transmission system reliability issues in 2012 and beyond (PJM, 2006b).

Congestion occurs when available energy cannot be delivered to all loads because transmission facilities do not have sufficient capacity. When the least expensive available energy cannot be delivered to loads in a transmission constrained area, higher cost units (energy) in the constrained area must be dispatched to meet that load. The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. The LMP reflects the price of the lowest cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus, LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying features of the power system, including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad, but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would permit direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load, and as a result, firm load receives the corollary financial hedge in the form of ARRs and/or FTRs. While the transmission system and ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load (PJM, 2006c).

In 1996, the Electricity Generation Customer Choice and Competition Act passed, giving electricity customers in Pennsylvania the ability to choose their electricity company. The selection of an electric generation supplier depends upon the area. Electric distribution companies provide the transmission and distribution, and the PPUC oversees electric service and competition in Pennsylvania. The quality, reliability, and maintenance of electric service have not changed under the Act. In fact, it enables customers to shop around for the price and type of service that best suits their needs (PPUC, 2007).

PJM's wholesale electricity market is similar to a stock exchange. It establishes a market price for electricity by matching supply with demand. Online eTools make trading easy for PJM members and customers by enabling them to submit bids and offers and providing them with continuous real time data. Market participants can follow market fluctuations as they happen and make informed decisions quickly and confidently. PJM members and customers can respond to high prices and bring resources to the region at times of high demand. PJM attempts to keep markets fair by making prices transparent through eTools.

In addition, as noted in Section 8.1 and Section 8.2, PJM is responsible for maintaining the integrity of the regional power grid and for managing changes and additions to the grid to accommodate new generating plants, substations, and transmission lines. PJM analyzes and forecasts the future electricity needs of the region. PJM also ensures that the growth of the electric system takes place efficiently, in an orderly, planned manner, and that reliability is maintained.

PJM market participants continually import energy from and export energy to external regions. The transactions involved may fulfill long term or short term bilateral contracts or take advantage of short term price differentials (PJM, 2006c).

- **Aggregate Imports and Exports.** During 2006, PJM was a net exporter of energy, with monthly net interchange averaging 1.5 million megawatt hours (MWh). Gross monthly import volumes averaged 2.2 million MWh, while gross monthly exports averaged 3.7 million MWh.

- **Interface Imports and Exports.** There were net exports at 15 of PJM's 21 interfaces in 2006. Three interfaces accounted for 65% of the total net exports: PJM/TVA with 33%, PJM/MidAmerican Energy Company with 17% and PJM/NYISO with 15% of the net export volume. There were net imports at five PJM interfaces. Three interfaces accounted for 97% of the net import volume, PJM/Ohio Valley Electric Corporation with 76%, PJM/Illinois Power Company with 12% and PJM/ Duke Energy Corporation with 9% of the net import volume.

8.3.1 REFERENCES

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Table 8.3-1—PJM Installed Capacity by Fuel Type in 2007

Fuel Type	January 1		May 31		June 1		December 31	
	MW	Percentage of Total	MW	Percentage of Total	MW	Percentage of Total	MW	Percentage of Total
Coal	66,613.5	40.9%	66,418.9	41.0%	66,546.0	40.7%	66,286.0	40.5%
Oil	10,771.1	6.6%	10,657.5	6.6%	10,645.0	6.5%	10,640.0	6.5%
Gas	47,528.0	29.2%	46,955.9	29.0%	47,557.0	29.1%	47,599.4	29.1%
Nuclear	30,056.8	18.5%	30,056.8	18.5%	30,880.8	18.9%	30,883.8	18.9%
Solid waste	719.6	0.4%	719.6	0.4%	714.6	0.4%	712.6	0.4%
Hydroelectric	7,122.9	4.4%	7,193.9	4.4%	7,287.2	4.5%	7,311.2	4.5%
Wind	28.8	0.0%	34.0	0.0%	28.8	0.0%	65.4	0.0%
Total	162,840.7	100.0%	162,036.6	100.0%	163,659.4	100.0%	163,498.4	100.0%

Note:
MW = megawatts

Table 8.3-2—PJM Generation Fuel Mix for 2007

Fuel Type	Power Generation (GWh)	Percentage of Total Generation
Coal	416,180.7	55.3%
Oil	3,728.1	0.5%
Gas	57,825.8	7.7%
Nuclear	255,040.1	33.9%
Solid waste	4,896.0	0.7%
Hydroelectric	13,080.6	1.7%
Wind	1,345.8	0.2%
Total	752,097.2	100.0%

Note:
GWh = Gega-watt hour

Table 8.3-3—PJM Capacity Additions

Year	Added Capacity (MW)
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265

Note:
MW = megawatts

Table 8.3-4—PJM Queued Capacity by Fuel Type in Pennsylvania

Fuel Type	Power Generation (MW)	Percentage of Total Generation
Diesel	39.0	0.1%
Coal	2,898.0	11.1%
Oil	97.0	0.4%
Natural Gas	13,534.9	51.9%
Nuclear	3,946.0	15.1%
Methane	95.5	0.4%
Hydroelectric	339.0	1.3%
Biomass	75.9	0.3%
Solar	3.0	0.0%
Wind	4,642.5	17.8%
Other	425.0	1.6%
Total	26,095.8	100.0%

Table 8.3-5—PJM Queued Generation Interconnection Requests in the ROI/Primary Market Area

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Queue	Plant Name	MW	MWC	Status	Schedule	TO	Fuel Type
Q41	Mt. Hope Mine 34.5 kV	30		Active	1/1/2008	JCPL	Biomass
Q59	S. Reading - Dirdsboro 64 kV	9	6.4	UC	3/31/2007	METED	Biomass
Q73	South Reading 69 kV	19	16	UC	12/15/2007	METED	Biomass
R42	Moselem 69 kV	6	6	UC	10/1/2007	METED	Biomass
R57	South Reading 69 kV	11	9	UC	1/16/2008	METED	Biomass
G04	Brunner Island #2	14	14	IS NC	1/1/2002	PPL EU	Coal
G05	Brunner Island #1	14	14	IS NC	5/1/2004	PPL EU	Coal
G06	Martins Creek #4	30	30	Active	12/1/2007	PPl EU	Coal
Q42	Indian River	630	630	Active	6/1/2012	DPL	Coal
Q90	Mickleton 230 kV	650	650	Active	6/1/2012	AEC	Coal
R04	Sunbury 500 kV	817	817	Active	12/15/2012	PPL EU	Coal
R24	Susquehanna-Alburtis 500 kV	940	940	Active	4/1/2012	PPL EU	Coal
R27	Frackville	52	52	Active	6/1/2010	PPL EU	Coal
R72	Indian River 230 kV	18	18	Active	6/1/0228	DPL	Coal
R73	Indian River 138 kV	5	5	Active	6/1/2008	DPL	Coal
O26	Pine Grove 69 kV	8	8	UC	1/1/2007	PPL EU	Diesel
S30	Gould	4	0	Active	12/31/2007	BGE	Diesel
Q20	Holtwood	140	140	Active	10/30/2010	PPL EU	Hydro
Q22	columbia 34.5 kV	0.5	0.5	UC	12/26/2008	JCPL	Hydro
R89	Conowingo	24	24	ISP	10/26/2006	PECO	Hydro
K04	Camden 26 kV	5		ISP	6/30/2005	PSEG	Methane
L03	Morgantown	0.8		Suspended	5/31/2009	PPL EU	Methane
M19	Otter Point	4.5		ISP	9/1/2006	BGE	Methane
N26	Daleville	1.6	1.6	ISP	11/1/2006	PECO	Methane
N27	Pequest River 34.5 kV	4	4	IS NC	7/1/2006	JCPL	Methane
N31	Freemansburg 69 kV	5		UC	7/31/2007	PPL EU	Methane
O11	Bustelton 13 kV	7.125	7.1	IS NC	6/1/2007	PSEG	Methane
O20	Lakehurst 34.5 kV	10	9.6	IS NC	12/31/0226	JCPL	Methane
O36	Honey Brook 12 kV	1.6		Active	12/1/2006	PPL EU	Methane
Q76	Quinton 12 kV	2	2	Active	11/1/2008	AEC	Methane
R74	Carlis Corner	4.8	4.8	Active	6/1/2008	AEC	Methane
R91	Columbus-NJ	0.37	0	Active	6/1/2007	PSEG	Methane
S40	Hegins	10.5	10.5	Active	10/15/2008	PPL	Methane
T11	Laurel-Sussex 69 kV	5	5	Active	8/14/2007	DPL	Methane
T12	Kent-harrington 69 kV	4	4	Active	8/14/2007	DPL	Methane
B19	Melrose 34.5 kV	20	20	IS NC	4/6/2001	JCPL	Natural Gas
C02	South Lebanon 230 kV	47	47	Active	1/1/2007	METED	Natural Gas
D01	Engleside 69 kV	1.6	1.6	IS NC	5/31/2000	PPL EU	Natural Gas
G20	Essex	6	6	IS NC	6/1/2003	PSEG	Natural Gas
G22	North Wales 34.5 kV	38	38	IS NC	9/30/2002	PECO	Natural Gas
H12	Edgemoor 230 kV	10	10	ISP	12/1/2005	DPL	Natural Gas
J05	Huron 69 kV	8	8	ISP	7/30/2003	AEC	Natural Gas
M07	Peckville (Aarchbald)	6	6.3	IS NC	3/15/2004	PPL EU	Natural Gas
P04	Peach Bottom 500 kV	550	550	UC	6/1/2008	PECO	Natrual Gas
P06	Cumberland 230 kV	366	550	Active	12/31/2008	AEC	Natural Gas
P23	Bayonne 138 kV	46	45.5	Active	6/1/2007	PSEG	Natural Gas
Q08	Red Oak 230 kV	50	50	Active	6/1/2008	JCPL	Natural Gas
Q11	Red Oak 230 kV	300	300	Active	6/1/2008	JCPL	Natural Gas

Table 8.3-5—PJM Queued Generation Interconnection Requests in the ROI/Primary Market Area

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Queue	Plant Name	MW	MWC	Status	Schedule	TO	Fuel Type
Q86	Hudson-Essex 230 kV	455.1	455.1	Active	5/31/2009	PSEG	Natural Gas
R11	South River 230 kV	611	611	Active	6/30/2009	JCPL	Natural Gas
R20	Rock Springs	20	20	IS NC	1/1/2007	PECO	Natural Gas
R23	Lakewood 230 kV	20	20	Active	1/1/2007	JCPL	Natural Gas
R39	Red Oak 230 kV	300	300	Active	6/30/2009	JCPL	Natural Gas
R58	Gloucester 230 kV	55	55	Active	6/1/2008	PSEG	Natural Gas
R66	Fair Lawn 138 kV	67	67	Active	3/1/2007	PSEG	Natural Gas
R81	Emilie 230 kV	120	120	Active	6/1/2008	PECO	Natural Gas
S03	Edgemoor 230 kV	5	5	Active	2/12/2007	DPL	Natural Gas
S121	Vineland 69 kV	63	63	Active	7/1/2008	AEC	Natural Gas
S122	Churchtown-Cumberland 230 kV	478	478	Active	11/1/2009	AEC	Natural Gas
S23	Graceton 230 kV	550	550	Active	6/1/2012	PECO	Natural Gas
S25	Parlin 230 kV	114	114	Active	7/1/2007	JCPL	Natural Gas
S32	Perryman	250	250	Active	5/1/2010	BGE	Natural Gas
S33	Riverside	120	85	Active	5/2/2010	BGE	Natural Gas
S60	Essex 26 kV	63	63	Active	6/1/2008	PSEG	Natural Gas
S61	Tosco 230 kV	20	20	Active	7/1/2007	PSEG	Natural Gas
S67	Gould St.	101	101	Active	6/1/2008	BGE	Natural Gas
T107	Essex 230 kV	675	675	Active	1/31/2012	PSEG	Natural Gas
T119	Sewaren 230 kV	600	600	Active	1/1/2012	PSEG	Natural Gas
T40	South Harrington	225	225	Active	6/1/2012	DPL	Natural Gas
T41	Kearny 230 or 138 kV	275	275	Active	6/1/2010	PSEG	Natural Gas
T42	Kearny 230 or 138 kV	138	138	Active	6/1/2012	PSEG	Natural Gas
T43	Essex 230 kV	205	205	Active	6/1/2010	PSEG	Natural Gas
T44	Essex 230 kV	205	205	Active	6/1/2012	PSEG	Natural Gas
T45	Husdon 230 kV	205	205	Active	6/1/2012	PSEG	Natural Gas
T51	Hay Road	13	13	Active	5/1/2008	DPL	Natural Gas
T52	Red Lion 500 kV	20	20	Active	5/1/2008	DPL	Natural Gas
T54	Cumberland 138 kV	9.4	9.4	Active	4/1/2009	AEC	Natural Gas
T55	Sherman Ave.	12.4	12.4	Active	4/1/2009	AEC	Natural Gas
T59	Mickleton	14.4	14.4	Active	4/1/2009	AEC	Natural Gas
T63	Carlis Corner	27.2	27.2	Active	4/1/2009	AEC	Natural Gas
T75	South River 230 kv	20	20	Active	9/25/2007	JCPL	Natural Gas
T76	south River 230 kV	40	40	Active	6/15/2009	JCPL	Natural Gas
T77	Linden 230 kV	64	64	Active	10/4/2007	PSEG	Natural Gas
T98	South Mahwah 69 kV	6	6	Active	10/29/2007	REC	Natural Gas
G46	Peach Bottom 500 kV	70	70	ISP	10/1/2007	PECO	Nuclear
H17	Salem 500 kV	115	115	ISP	6/1/2008	PSEG	Nuclear
H18	Hope Creek 500 kV	78	78	ISP	12/1/2007	PSEG	Nuclear
H19	Hope Creek 500 kV	43	43	UC	12/1/2007	PSEG	Nuclear
M11	Susquehanna #1	111	111	UC	7/1/2008	PPL EU	Nuclear
M12	Susquehanna #2	107	107	UC	7/1/2007	PPL EU	Nuclear
Q47	Peach Bottom	140	140	Active	10/31/2012	PECO	Nuclear
Q48	Calvert Cliffs	1640	1640	Active	12/31/2015	CEG	Nuclear
R01	Susquehanna	800	800	Active	1/1/2013	PPL EU	Nuclear
R02	Susquehanna	800	800	Active	1/1/2013	PPL EU	Nuclear
T182	TMI 230 kV	24	24	Active	1/31/2008	METED	Nuclear
N34	Motiva	142	142	ISP	5/1/2002	DPL	Oil

Table 8.3-5—PJM Queued Generation Interconnection Requests in the ROI/Primary Market Area
(Page 3 of 3)

Queue	Plant Name	MW	MWC	Status	Schedule	TO	Fuel Type
Q74	Linden 230 kV	600	600	Active	6/1/2009	PSEG	Oil
S43	Vineland	17	17	Active	6/1/2008	AEC	Oil
T53	Delaware City	7.3	7.3	Active	6/1/2008	DPL	Oil
T56	Christiana	10.4	10.4	Active	4/1/2009	DPL	Oil
T57	Middle	22.2	22.2	Active	4/1/2009	AEC	Oil
T60	Missouri Ave.	10.5	10.5	Active	4/1/2009	AEC	Oil
T61	Cedar	8.3	8.3	Active	4/1/2009	AEC	Oil
T66	Tasley	6.7	6.7	Active	4/1/2009	DPL	Oil
T66	Tasley	6.7	6.7	Active	10/1/2008	DPL	Oil
T67	West	7.6	7.6	Active	4/1/2009	DPL	Oil
T68	Edgemoor	9.6	9.6	Active	4/1/2009	DPL	Oil
K21	East Carbondale 69 kV	70	13	IS NC	7/1/2004	PPL EU	Wind
O28	Jenkins-Harwood #2 69 kV	85	17	Active	9/30/2006	PPL EU	Wind
O39	Sunbury-Dauphin 69 kV	56	11.2	Suspended	12/15/2007	PPL EU	Wind
O40	Pine Grove-Frailey 69 kV	28	5.6	Active	12/15/2007	PPL EU	Wind
O70	Susquehanna Hardwood 230 kV	124	24.8	UC	12/15/2007	PPL EU	Wind
P03	Frackville-Hauto #3	1	0.26	IS NC	12/31/2007	PPL EU	Wind
Q27	Frackville-Shennandoah 69 kV	100	20	Active	12/31/2007	PPL EU	Wind
Q28	Eldred-Frackville 230 kV	220	44	Active	12/31/2008	PPL EU	Wind
Q40	Renovo Lock Haven	40	8	Active	6/26/2006	PPL EU	Wind
Q58	Sunbury-Susquehanna	100	20	Active	12/31/2008	PPL EU	Wind
R36	Bethany 138 kV	450	90	Active	6/1/2014	DPL	Wind
R37	Rehoboth 138 kV	450	90	Active	6/1/2014	DPL	Wind
R43	Frackville Hauto #3	20	4	Active	12/31/2006	PPL EU	Wind
R53	Stanton-Brookside 69 kV	60	12	Active	11/11/2008	PPL EU	Wind
S20	Pine Grove-Fishbach 69 kV	50	10	Active	10/1/2009	PPL EU	Wind
T122	Ocean Bay 138 kV	600	120	Active	6/1/2015	DPL	Wind
T81	Cedar 230 kV	350	70	Active	12/31/2012	AEC	Wind
T82	Cardiff 230 kV	350	70	Active	12/31/2012	AEC	Wind
T83	Merion 138 kV	350	70	Active	12/31/2012	AEC	Wind
T84	Corson 138 kV	350	70	Active	12/31/2012	AEC	Wind

Note:
AEC = Atlantic Electric Company
BGE= Baltimore Gas and Electric Company
DPL= Delmarva Power & Light
IS NC = In-service, no capacity. Indicates a generator that is in-service for energy only. Such units have not requested consideration for capacity status.
ISP = In-service, partial. Denotes a generating resource that is only partially in-service and has not reached full capacity status. A generating unit is ineligible for full capacity status until all transmission upgrades needed to ensure deliverability are completed. Only then will PJM grant capacity status designation.
JCPL = J ersey Central Power & Light
METED = Metropolitan Edison Company
PECO = PECO Energy company
PPL EU = PPL Electric Utilities Corporation
PSEG = Public Service Electric & Gas Company
REC = Rockland Electric Company
UC = Under Construction
MW = Total Energy Output of Facility
MWC = Capacity Component of Total Energy Output of Facility
TO = Transmission Owner

Table 8.3-6—Capacity Additions (MW) in Active or Under-Construction Queues by Control Zone

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	225	695	9	0	0	650	0	1,579
AEP	0	646	247	144	84	6,059	3,255	10,435
AP	640	600	11	81	0	1,955	2,268	5,555
BGE	0	961	8	0	3,280	0	0	4,249
ComEd	600	835	105	0	280	765	13,049	15,634
DAY	0	37	2	0	0	1,300	983	2,322
Dominion	1,633	1,235	148	94	1,944	280	0	5,334
DPL	0	305	23	0	0	653	1,598	2,579
JCPL	1,261	194	40	1	0	0	0	1,496
Met-Ed	47	1,200	66	0	0	0	0	1,313
PECO	550	4,540	6	0	140	0	3	5,239
PENELEC	0	153	12	32	0	310	2,778	3,285
Pepco	1,250	2,388	5	0	0	0	0	3,643
PPL	0	42	38	140	1,018	5,402	1,277	7,917
PSEG	1,100	1,909	74	0	43	0	0	3,126
UGI	0	0	0	0	0	300	0	300
Total	7,306	15,740	794	492	6,789	17,674	25,211	74,006

Notes: Data are current as of December 31, 2007.

Table 8.3-7—Existing PJM Capacity (MW): 2007

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	155	528	14	0	0	1,108	8	1,813
AEP	4,361	3,577	0	1,008	2,093	21,711	0	32,750
AP	1,129	1,159	43	80	0	7,862	81	10,354
BGE	0	872	0	0	1,735	2,793	0	5,400
ComEd	1,790	6,172	0	0	11,448	6,916	343	26,669
DAY	0	1,316	44	0	0	4,079	0	5,439
DLCO	272	45	0	0	1,630	3,524	0	5,471
Dominion	2,515	3,213	105	3,321	3,459	8,332	0	20,945
DPL	1,088	801	86	0	0	1,780	0	3,755
External	0	100	0	0	0	5,605	0	5,705
JCPL	1,569	1,216	6	333	619	10	0	3,753
Met-Ed	1,984	417	0	19	786	817	0	4,023
PECO	2,497	1,498	6	1,618	4,492	2,022	0	12,133
PENELEC	0	332	50	76	0	6,805	119	7,782
Pepco	1,134	1,321	0	0	0	4,774	0	7,229
PPL	1,674	613	39	568	2,003	5,697	112	10,706
PSEG	2,849	2,975	13	8	3,353	2,264	0	11,462
Total	23,017	26,155	406	7,431	31,618	86,099	663	175,389

Table 8.3-8—PJM Queued LTFTS Requests (12/31/2007)

Queue Number	Status	Transfer	MW
S58B	ACTIVE	AMIL - PJM	240
S53C	ACTIVE	AP - PSEG	125
S53B	ACTIVE	AP - DPL	125
S58C	ACTIVE	PJM - Cinergy	100
S58D	ACTIVE	AP - Dominion	400
S59B	ACTIVE	PJM - Cinergy	
S04B	ACTIVE	PJM - Cinergy	300
T17	ACTIVE	PJM - Duke Energy	106
T18	ACTIVE	PJM - Duke Energy	106
T19	ACTIVE	PJM - Duke Energy	106
T36	ACTIVE	LG&E - Duke Energy	62
T46	ACTIVE	PJM - Cinergy	80
T95	ACTIVE		
T96	ACTIVE		
T97	ACTIVE		
T90	ACTIVE		
T15	ACTIVE		
T72	ACTIVE	NYISO - PJM - NYISO	

Notes:

LTFTS = long-term firm transmission service
MW = megawatts
AMIL = Ameren (Illinois)
PJM = Pennsylvania-New Jersey-Maryland Interconnection
AP = Allegheny Power
PSEG = Public Service Electric & Gas Company
DPL = Delmarva Power & Light
LG&E = Louisville Gas and Electric Company
NYISO = New York Independent System Operator

Source: PJM, 2008e

Table 8.3-9—PJM Queued ARR Requests (12/31/2007)

Queue Number	Status	Source	Sink
S07	ACTIVE	Keystone	Branchburg
S08	ACTIVE	Kammer	Doubs
S09	ACTIVE	Conemaugh	Conastone
S10	ACTIVE	Jacksons Ferry	Burches Hill

Notes:
ARR = Auction Revenue Rights
Source: PJM, 2008e

Table 8.3-10—Generator Deactivations
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Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Actual Deactivation Date	PJM Reliability Status
Warren 1	41	PN	54		9/27/2002	9/28/2002	No Reliability Issues
Warren 2	41	PN	53		9/27/2002	9/28/2002	No Reliability Issues
Hudson 3 CT	129	PS	36	10/16/2003	10/16/2003	10/17/2003	No Reliability Issues
Seward 4	60	PN	53	11/19/2003	11/19/2003	11/20/2003	No Reliability Issues
Seward 5	136	PN	47	11/19/2003	11/19/2003	11/20/2003	No Reliability Issues
Gould Street	101	BGE	51	11/4/2003	11/1/2003	12/1/2003	No Reliability Issues
Sayreville 4	114	JC	49	11/1/2003	2/14/2004	2/19/2004	Reliability Issues Identified and Resolved
Sayreville 5	115	JC	45	11/1/2003	2/14/2004	2/19/2004	Reliability Issues Identified and Resolved
Delaware 7	126	PE	50	12/12/2003	3/1/2004	3/5/2004	No Reliability Issues
Delaware 8	124	PE	51	12/12/2003	3/1/2004	3/5/2004	No Reliability Issues
Burlington 101-104	208	PS	10	1/8/2004	4/4/2004	4/4/2004	No Reliability Issues
Burlington 105	52	PS	31	1/8/2004	4/4/2004	4/4/2004	No Reliability Issues
Wayne CT	56	PN	31	2/12/2004	As soon as possible	5/5/2004	No Reliability Issues
Sherman VCLP	46.6	AE	9	2/2/2004	3/15/2004	6/25/2004	No Reliability Issues
Calumet 31	56	CE	36	10/12/2004	Currently Mothballed - As soon as possible	7/1/2004	No Reliability Issues
Calumet 33	42	CE	36	10/12/2004	Currently Mothballed - As soon as possible	7/1/2004	No Reliability Issues
Calumet 34	51	CE	35	10/12/2004	Currently Mothballed - As soon as possible	7/1/2004	No Reliability Issues
Joliet 31	59	CE	36	10/12/2004	Currently Mothballed - As soon as possible	7/1/2004	No Reliability Issues
Joliet 32	57	CE	36	10/12/2004	Currently Mothballed - As soon as possible	7/1/2004	No Reliability Issues

Table 8.3-10—Generator Deactivations
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Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Actual Deactivation Date	PJM Reliability Status
Warren 3 CT	57	PN	31	2/12/2004	Mothballed on 5/1/2004, relisted from 7/1/04 until 10/1/04	10/1/2004	No Reliability Issues
Bloom 33	24	CE	33	10/12/2004	Currently Mothballed - As soon as possible	NA - never a PJM capacity resource	No Reliability Issues
Bloom 34	26	CE	33	10/12/2004	Currently Mothballed - As soon as possible	NA - never a PJM capacity resource	No Reliability Issues
Collins 1	554	CE	26	6/2/2004	12/31/2004	1/1/2005	No Reliability Issues
Collins 2	554	CE	27	6/2/2004	3rd/4th Quarter 2004	1/1/2005	No Reliability Issues
Collins 3	530	CE	27	6/2/2004	12/31/2004	1/1/2005	No Reliability Issues
Collins 4	530	CE	26	6/2/2004	Currently Mothballed - As soon as possible	1/1/2005	No Reliability Issues
Collins 5	530	CE	25	6/2/2004	Currently Mothballed - As soon as possible	1/1/2005	No Reliability Issues
Riegel Paper NUG (Milford Power LP)	27	JC	33	6/11/2004	Planned to retire 6/30/04, request delayed until 12/31/04	1/1/2005	No Reliability Issues
STI 3 & 4 (Cat Tractor)	20	ME	15	9/29/2004	1/1/2005	1/1/2005	No Reliability Issues
Electric Junction 31	59	CE	34	10/12/2004	12/31/04 - when contract is complete	1/1/2005	No Reliability Issues after 1/1/05
Electric Junction 32	59	CE	34	10/12/2004	12/31/04 - when contract is complete	1/1/2005	No Reliability Issues after 1/1/05
Electric Junction 33	59	CE	34	10/12/2004	12/31/04 - when contract is complete	1/1/2005	No Reliability Issues after 1/1/05
Lombard 32	31	CE	35	10/12/2004	Currently Mothballed - As soon as possible	1/1/2005	No Reliability Issues
Lombard 33	32	CE	35	10/12/2004	Currently Mothballed - As soon as possible	1/1/2005	No Reliability Issues

Table 8.3-10—Generator Deactivations

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Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Actual Deactivation Date	PJM Reliability Status
Sabrooke 31	25	CE	35	10/12/2004	12/31/04 - when contract is complete	1/1/2005	No Reliability Issues
Sabrooke 32	25	CE	35	10/12/2004	12/31/04 - when contract is complete	1/1/2005	No Reliability Issues
Sabrooke 33	24	CE	34	10/12/2004	12/31/04 - when contract is complete	1/1/2005	No Reliability Issues after 1/1/05
Sabrooke 34	13	CE	34	10/12/2004	12/31/04 - when contract is complete	1/1/2005	No Reliability Issues after 1/1/05
Madison St. CT	10	DPL	41	10/13/2004	12/31/2004	1/7/2005	No Reliability Issues
Crawford 31	59	CE	36	10/12/2004	As soon as possible	3/1/2005	Reliability issue identified and resolved
Crawford 32	58	CE	36	10/12/2004	As soon as possible	3/1/2005	Reliability issue identified and resolved
Crawford 33	59	CE	36	10/12/2004	As soon as possible	3/1/2005	Reliability issue identified and resolved
Deepwater CT A	19	AE	37	10/13/2004	4/1/2005	5/1/2005	Reliability Issue resolved (Blackstart)
Kearny 7	150	PS	51	9/8/2004	12/7/2004	6/1/2005	Reliability issue identified and resolved
Kearny 8	150	PS	50	9/8/2004	12/7/2004	6/1/2005	Reliability issue identified and resolved
Howard M. Down (Vineland) Unit 7	8	AE	53	2/24/2005	5/31/2005	6/17/2005	No Reliability Issues
DSM (Hoffman LaRoche)	9	JC	7	9/1/2005	10/1/2005	10/6/2005	No Reliability Issues
Newark Boxboard	52	PS	15	7/6/2005	10/5/2005	10/11/2005	Reliability issue identified and expected to be resolved by 6/2007

Table 8.3-10—Generator Deactivations
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Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Actual Deactivation Date	PJM Reliability Status
Conesville 1	115	AEP	46	9/20/2005	12/31/2005	1/1/2006	Reliability issue (black start) identified and resolved
Conesville 2	115	AEP	48	9/20/2005	12/31/2005	1/1/2006	Reliability issue (black start) identified and resolved
Gude Landfill 1&2	2.2	PEP	20	8/12/2004	3/25/2006	3/25/2006	No Reliability Issues
Bayonne CT1	21	PS	35	3/30/2006	As soon as possible	5/20/2006	No Reliability Issues
Bayonne CT2	21	PS	35	3/30/2006	As soon as possible	5/20/2006	No Reliability Issues
Delaware Diesel	2.7	PE	39	8/30/2006	As soon as possible	10/24/2006	No Reliability Issues
Buzzard Point East Bank 3	16	PEP	39	2/28/2007	5/31/2007	5/31/2007	Reliability Issues Identified
Martins Creek 1	140	PPL	53	3/19/2004	9/15/2007	9/15/2007	No Reliability Issues
Martins Creek 2	140	PPL	51	3/19/2004	9/15/2007	9/15/2007	No Reliability Issues
Martins Creek D1-D2	5	PPL	40	9/1/2005	9/15/2007	9/15/2007	Reliability issue (black start) identified and resolved
Waukegan 6	100	CE	55	1/3/2007	9/1/2007	12/31/2007	No Reliability Issues

Table 8.3-11—Distribution of PJM Energy Resources

	2006 Capacity	2005 Generation	2006 Generation
Coal	41%	56%	57%
Nuclear	18%	34%	34%
Hydro, Wind and other	5%	3%	3%
Oil	7%	1%	0%

Table 8.3-12—Historical Reserve Requirement Study (RRS) Parameters

RRS Year	Delivery Year	Calculated IRM	Approved IRM
2000	2000/2001	18.3%	19.5%
2001	2001/2002	17.4%	19.0%
2002	2002/2003	19.0%	19.0%
2003	2003/2004	16.4%	17.0%
2004	2005/2005	14.9%	16.0%
2005	2005/2006	14.5%	15.0%
	2006/2007	14.7%	15.0%
2006	2007/2008	14.6%	15.0%
	2008/2009	14.6%	15.0%
	2009/2010	14.7%	15.0%

Source: PJM, 2007b

8.4 ASSESSMENT OF NEED FOR POWER

As introduced at the beginning of Chapter 8, the NRC may rely on need for power analyses prepared by states or regions as the basis for the NRC evaluation if they are: (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty (NRC, 2007).

In assessing the costs and benefits of the project, ESRP 8.4 provides the following review criterion (NRC, 2007):

> *If a need for power analysis conducted by or for one or more relevant regions affected by the proposed plant concludes there is a need for new generating capacity, that finding should be given great weight provided that the analysis was systematic, comprehensive, subject to confirmation, and responsive to forecast uncertainty. This source may be the most appropriate if the proposed plant is not planned to serve a traditional utility load or as a retail power supplier in a specific region, but is expected to provide power as a merchant plant to a regional wholesale power market. In this case, the analysis of the relevant market should include an assessment of competitors to the proposed plant.*

The NRC further notes the following (NRC, 2007):

> *Although this criterion does not show a need for baseload capacity, it does demonstrate a need for new capacity that is independent of type. This criterion, coupled with an affirmative indication that there is a need for baseload capacity, justifies a baseload addition within the time span determined by the reviewer's forecast analysis.*

8.4.1 ASSESSMENT OF THE NEED FOR NEW CAPACITY

As noted in Section 8.3, reserve margin is the amount by which the capacity resources exceed the peak demand and is expressed as a percentage of the demand. Although the annual reserve margin defines only the relationship between capacity and demand for the peak hour of the year, it is derived from a probabilistic assessment method. RFC Standard BAL 502 RFC 01 requires a probabilistic assessment that utilizes generation resources and peak demand duration characteristics be conducted for each LSE, individually or in Planned Reserve Sharing Groups (PRSGs). A reserve margin derived from PRSG probabilistic assessments will be the measure used to evaluate the projected reliability of the Region beginning in 2008. There is no single probability study for the entire RFC region; although, each of the three heritage regions (East Coast Area Reliability Coordination Agreement (ECAR), MAAC, and Mid America Interconnected Network, Inc. (MAIN) has previously prepared probability studies that are applicable to its portion of RFC. The reserve margins calculated in this assessment are being compared to the most conservative margin from those heritage region studies, which is the 15% reserve margin established for the 2005 MAAC Reliability Assessment for summer 2006. In 2008, the reserve margins established by the PRSGs within RFC will be used to assess the resource adequacy of each PRSG within the region.

This analysis evaluates the adequacy of the capacity in the region to supply the demand in the region. Interchange transactions and ownership of generating capacity that create power flows in and out of the RFC regional area are not included as capacity resources in this assessment. This means that power purchases from outside the region and power sales to entities outside the region are excluded from the analysis. It also means that capacity owned by members but located outside the region is excluded, while capacity located within the region, although owned by entities outside the region, is included in this assessment as a capacity resource (RFC, 2007).

With the addition of more than 3,000 MW of planned new capacity by 2010, the reserve margins are expected to remain above 15% through 2010. Table 8.4-1 (RFC, 2007) summarizes the projected reserve margins for each summer peak demand period, from 2007 through 2016. Three sets of reserve margins are listed in the table: one based on the existing (2007) capability, a second based on existing and planned capability, and a third set of reserve margins based on the existing planned, and potential capability. Based on existing resources, projected retirements and capability changes through summer 2016, the reserve margins based on the summer peak net internal demand (NID) are projected to decline from a high of 20.4% in 2007, to a low of 5.1% in 2016. This is an improvement over last year's 18.0% reserve margin for 2007 that is projected to decline to 1.6% by 2016. The projected reserve margins for the summer peak NID, based on existing and planned capacities plus the existing uncommitted and energy only resources, decline over the period from 23.3% in 2007 (compared with 21.3% last year) to 9.6% in 2016 (compared with 9.2% last year).

These two projections of reserve margins from 2007 to 2016 represent the likely range for the actual reserve margin, although neither extreme is considered likely to occur. A third reserve margin projection (existing and planned resources) depicts the reserve margins when the uncommitted and energy only resources are excluded from the total resource capability.

The earliest date when reserve margin would be expected to fall below 15% is 2010, assuming no new capacity additions. The amount of new capacity needed to meet a 15% reserve margin in 2010 is about 500 MW after retirements and changes to existing capacity. Retirements and changes are expected to provide a net reduction of existing capability by about 1,000 MW.

While uncertainty in the existing data prevents a precise forecast of when the reserve margins may decline below 15%, there appears to be sufficient lead time for the industry to respond such that a 15% reserve margin can be maintained (RFC, 2007). As a result, not only will there be a need for power from the BBNPP, there will be a need for a substantial amount of other new generating capacity.

In this regard, a number of companies, considered to be probable competitors, have announced their intentions to build new baseload generating capacity in the PJM region (see Table 8.3-5 [PJM, 2008a]). Additionally, other companies have announced their intentions to construct other types of generation capacity, including fossil fueled facilities and wind turbine systems. However, only the following capacity which may be utilized as baseload capacity were included in the 2007 PJM resources forecast:

- 670 MW of new gas fired generation capacity (in 2008),
- 750 MW of coal fired generation capacity (in 2012), and
- 800 MW of coal fired generation capacity (in 2012).

As noted in Section 8.1, reliability standards for the RFC require that sufficient generating capacity be installed to ensure that the probability of the system load exceeding available capacity is no greater than 1 day in 10 years. The RFC reliability standard is closely related to the 15% reserve margin objective. Studies are performed each year to determine the future required reserve margins to meet the RFC reliability standard.

The load serving entities have a capacity obligation determined by evaluating individual system load characteristics, unit size, and operating characteristics. Additionally, PJM conducts load deliverability tests that are a unique set of analyses designed to ensure that the transmission system provides a comparable transmission function throughout the system. The transmission system reliability criterion used is one event of failure in 25 years. This is intended to design transmission so that it is not limiting the planned generation system to a reliability criterion of one event in 10 years. (PJM, 2008b)

In summary, the RFC and PJM assessments have forecasted a shrinking reserve margin that does not satisfy RFC and PJM goals to maintain system reliability by 2010 (see Table 8.4-1 [RFC, 2007]). By the time the BBNPP is projected to enter commercial operation in December 2018, there will be a substantial need for power, not only from the BBNPP, but from other new generating plants, as well.

As discussed in Section 8.2.2, in 2007, PJM initiated the Reliability Pricing Model (RPM) to correct current capacity shortcomings and to forestall reliability concerns throughout the RTO. PJM assumed the following factors for its growing concern about reliability and power supply (PJM, 2008a):

- Continued load growth including impending exports of power to the New York City area. The New Jersey area, the greater Baltimore area, the nation's capital, and the Delmarva Peninsula are fast-growing major population centers.
- Retirement of generation resources. There has been a high level of generation retirements announced in parts of the RTO with little advance warning.
- Sluggish development of new generation facilities. Underlying trends of comparatively low generation additions exist.
- Continued reliance on transmission to meet load deliverability requirements and to obtain additional sources of power from the west. Constraints principally occur on flows into eastern Pennsylvania and New Jersey (and from there to New York City) from western Pennsylvania and from the Chesapeake Bay region.

The RFC process is a national one, set up by NERC to comply with EIA data gathering requirements. The corporation gathers the data on an annual basis, compiles it, and submits it to NERC as a region specific composite. NERC submits the data to EIA as a national composite together with region specific information. PPL has concluded that the statutory, regulatory, and administrative requirements that make up the PJM and NERC processes comprise methodical regional processes for systematically reviewing the need for power that PPL intends to help meet.

8.4.2 OTHER BENEFITS OF NEW NUCLEAR CAPACITY

NUREG 1555 allows an applicant to assess the need for a proposed power generating facility on other grounds. The following criteria suggest the continuing benefits of and the need for a new merchant baseload generating facility (NRC, 2007):

The relevant region's need to diversify sources of energy (e.g., using a mix of nuclear fuel and coal for baseload generation).

The potential to reduce the average cost of electricity to consumers.

The nationwide need to reduce reliance on petroleum.

The case of a significant benefit cost advantage being associated with plant operation before system demand for the plant capacity develops.

In addition, the 2005 EPACT encourages needed investment in the nation's energy infrastructure, helps boost electric reliability, and promotes a diverse mix of fuels to generate electricity. This Act includes a number of provisions that will affect the cost and availability of energy and the overall structure of the electricity and natural gas industries.

Although NUREG 1555 does not specifically identify GHG reduction as one of these benefits, more recent state and national policy statements assert the benefits of baseload capacity that reduces GHG. The increasing concern about GHG and consequent climate change has triggered a number of national policy trends:

- During the 109th Congress, both houses of the U.S. Congress introduced resolutions calling for a national program of carbon reduction. The Senate Committee on Energy and Natural Resources is reviewing "cap and trade" legislation to reduce GHG emissions during the early days of the 110th Congress (U.S. Senate, 2006).

- The 110th Congress continues its exploration of legislation that would limit carbon emissions in the United States. Known as "cap and trade" legislation, the legislation seeks to bring carbon emissions down through a series of industry caps and trading strategies (U.S. Senate, 2007a).

- Costs of climate change have also triggered concerns about the economic effects of continuing carbon emission growth. The following examples highlight the growing concern in the United States:

    - A British study reviewed by the U.S. Senate notes that unabated climate change will sharply affect economic systems globally, ultimately costing more than 20% annually of gross domestic product by the year 2050 (U.S. Senate, 2007b).

    - U.S. economic reviews of the British study support it with "high confidence" (Yohe, 2007).

8.4.3 SUMMARY OF NEED FOR POWER

PJM planning is subject to review by its Board of Directors and advisory board. The PJM reliability planning processes are also confirmable by comparing forecasts to RFC composite forecasts. Although the PJM forecasts are included in the RFC regional composite, the regional composite includes forecasts by many other generators and suppliers.

PJM uses commercially developed software to perform uncertainty analyses to account for forecasting uncertainty. Each uses econometric modeling that enables them to perform analyses of the sensitivity of results to changes in model inputs and to create high and low range forecasts. Uncertainty analysis is also used in establishing planning reserve margins, themselves an acknowledgement of uncertainty.

PPL concludes that PJM has the kind of reliability planning process that meets the NRC criteria for an acceptable regional need for power analysis. Similarly, PPL concludes that the RFC process for gathering need for power data provides further satisfaction of NRC criteria at the regional level. At the regional level, growth projections support the need for the power that the proposed BBNPP would produce.

The purpose of the proposed BBNPP is to satisfy the need for power identified by PJM. The result of No Action, or not constructing the new facility, would mean that the need for power has not been satisfied, and other electric generating sources would be needed to meet the forecasted electricity demands.

In summary, the benefits of the proposed BBNPP include the following:

- The proposed BBNPP would alleviate existing congestion in the west-to-east transmission of energy across the Allegheny Mountains.
- The proposed BBNPP would provide much needed baseload power for an area that is expected to have the average annual peak forecast grow between 1.2 and 1.5% per year over the next 10 years.
- The proposed BBNPP would allow PJM to continue to meet the growing demand for an average of 1,654 MW per year of added capacity since 2000.
- The proposed BBNPP would enable PJM to sustain the reserve margins necessary to prevent a reduction in the supply of energy and to meet the expected future demand trends.
- Given concerns throughout the northeastern United States about climate change and carbon emissions, the proposed BBNPP serves another important need by reducing carbon emissions. The proposed BBNPP would displace significant amounts of carbon as soon as the plant becomes operational, as compared to the coal fired generation that likely would be expected to meet the identified need for power.

ER Section 9.2 discusses the viability of various baseload energy alternatives. ER Section 10.4 further reviews the costs and benefits of the proposed BBNPP.

It is expected that regional transmission organizations (i.e., PJM) prepare need-for-power evaluations for proposed generation and transmission facilities. BBNPP will be located in the PJM RTO territory. The PJM evaluations prepared are systematic, comprehensive, subject to confirmation and responsive to forecasting uncertainty. Therefore, the BBNPP's need for an assessment for power satisfies the criteria noted in NUREG-1555, Section 8.4 (NRC, 2007).

8.4.4 REFERENCES

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Table 8.4-1—Demand, Capability, and Margins 2007 – 2016 (Summer)

	2007	2008	2009	2010	2012	2012	2013	2014	2015	2016
Demand										
RFC NID, MW	180,400	182,500	185,600	188,400	191,300	194,100	196,900	199,500	202,400	205,300
Capability										
Existing Seasonal Capacity (NSC), MW	217,129	216,751	216,033	216,140	215,960	215,926	215,801	215,801	215,801	215,801
Planned Additions (NSC), MW		1365	2440	3047	3747	3847	3847	3847	3847	3847
Planned Seasonal Capability (NSC), MW	217,129	218,116	218,473	219,187	219,697	219,773	219,648	219,648	219,648	219,648
Uncommitted and Energy-Only Capability (NSC), MW	5300	5300	5300	5300	5300	5300	5300	5300	5300	5300
Potential Seasonal Capability (NSC), MW	222,429	223,416	223,773	224,487	224,987	225,073	224,948	224,948	224,948	224,948
Reserve Margins (MW & % of NID)										
Reserve Margins with Existing Resources	36,729 20.4%	34,251 18.8%	30,433 16.4%	27,740 14.7%	24,650 12.9%	21,826 11.2%	18,901 9.6%	16,301 8.2%	13,401 6.6%	10,501 5.1%
15% Reserve Margin – Surplus (Deficit)	9669	6976	2593	(520)	(4045)	(7289)	(10,634)	(13,624)	(16,959)	(20,294)
Reserve Margins with Existing and Planned Resources	36,729 20.4%	35,616 19.5%	32,873 17.7%	30,787 16.3%	28,397 14.8%	25,673 13.2%	22,748 11.6%	20,148 10.1%	17,248 8.5%	14,348 7.0%
15% Reserve Margin – Surplus (Deficit)	9669	8241	5033	2527	(298)	(3442)	(6787)	(9777)	(13,112)	(16,447)
Reserve Margins with Existing, Planned, and Potential Resources	42,029 23.3%	40,916 22.4%	38,173 20.6%	36,087 19.2%	33,697 17.6%	30,973 16.0%	28,048 14.2%	25,448 12.8%	22,548 11.1%	19,648 9.6%
15% Reserve Margin – Surplus (Deficit)	14,696	13,541	10,333	7827	5002	1858	(1487)	(4477)	(7812)	(11,147)

Note:
NSC = Net seasonal Capability
MW = MegaWatt
NID = Net Internal Demand
Installed Reserve Margin (IRM) -is the percentage which represents the amount of installed capacity required above the forecasted peak load required to satisfy a loss of load expectation (LOLE) of 1day/10 years. The IRM is expressed in units of installed capacity.
Calculated IRM - is the installed reserve that is determined by a PJM study performed each spring using a probabilistic model that recognizes, among other factors, historical load variability, load forecast error, scheduled maintenance requirements for generating units, forced outage rates of generating units and the capacity benefit of interconnection ties with other regions.
Approved IRM - is the installed reserve that is approved by the PJM Board, as a result of the review process and recommendations of the calculated IRM study by the PJM committee structure and the PJM Members Committee to the PJM Board.