GT GreenbergTraurig

Doreen U. Saia
Tel. (518) 689-1430
Fax (518) 677-1854
saiad@gtlaw.com

October 16, 2013

VIA E-FILE

(Secretary@dps.ny.gov)

Hon. Kathleen H. Burgess
Secretary
New York State Public Service Commission
Empire State Plaza
Agency Building 3
Albany, NY 12223-1350

Re: Case No. 12-E-0503: Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans
Motion to Lodge

Dear Secretary Burgess:

Pursuant to Section 3.6 of the New York Public Service Commission's Rules and Regulations, enclosed is the Motion to Lodge of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, Entergy Nuclear FitzPatrick, LLC and Entergy Nuclear Operations, Inc.

A copy of this Motion has been served on the parties to this proceeding. If you have any questions concerning this filing, please contact me.

Very truly yours,

GREENBERG TRAURIG, LLP

Doreen U. Saia

Doreen U. Saia

DUS/sm
Enclosure

cc: Official Service List (w/enc.; via electronic mail or U.S. mail)

ALB 1729736v1

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission To Review Generation Retirement Contingency Plans	)))	**Case 12-E-0503**

MOTION TO LODGE OF ENTERGY NUCLEAR INDIAN POINT 2, LLC, ENTERGY NUCLEAR INDIAN POINT 3, LLC, ENTERGY NUCLEAR FITZPATRICK, LLC AND ENTERGY NUCLEAR OPERATIONS, INC.,

PRELIMINARY STATEMENT

On November 30, 2012, the New York Public Service Commission ("PSC") initiated this proceeding targeted solely at the potential system impacts in southeastern New York if a single generating facility, the Indian Point facility,[1] ultimately ceased operations.[2] Acknowledging that Indian Point's owners had filed an application with the Nuclear Regulatory Commission ("NRC") to obtain a 20-year license renewal for the facility, the PSC determined that "significant advanced planning" was nevertheless required to address system reliability under a hypothetical Indian Point closure scenario.[3] Pursuant to Section 3.6 of the PSC's Rules and Regulations, Entergy hereby moves to lodge the October 11, 2013 decision issued by the United States District Court for the District of New Jersey, annexed hereto as Attachment I, because it directly

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[1] The Indian Point facility is comprised of Indian Point Unit 2 and Indian Point Unit 3, which are located on the same site in Buchanan, New York. The Indian Point facility is collectively referred to herein as "Indian Point."

[2] See Case 12-E-0503, supra, "Order Instituting Proceeding and Soliciting Indian Point Contingency Plans" (issued November 30, 2012) (hereinafter, "RCP Proceeding" and "November Order," respectively). Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, Entergy Nuclear FitzPatrick, LLC and Entergy Nuclear Operation, Inc. (collectively, "Entergy") intervened in the RCP Proceeding and has actively participated in every stage of this proceeding.

[3] Id. at p. 2 (footnote omitted). The PSC has acknowledged throughout this proceeding that there are no reliability needs on the system at the present time with Indian Point continuing to be in service.

pertains to the threshold jurisdictional issues that have repeatedly been raised throughout this proceeding.[4]

BACKGROUND

To meet its identified need for significant advanced planning, the PSC directed the Consolidated Edison Company of New York, Inc. ("Con Edison"), with the New York Power Authority's ("NYPA") assistance, to develop and file a contingency plan.[5] On February 1, 2013, Con Edison and NYPA submitted the Joint Plan.[6] The Joint Plan proposed, inter alia, several, State-based cost allocation and cost recovery theories for the TO Projects and the NYPA RFP Projects.[7] The Joint Plan did not address the PSC's authority to grant the State-based cost allocation and cost recovery relief requested therein.

The November Order established that comments on the Joint Plan were due on February 22, 2013.[8] In accordance with the November Order, a number of parties submitted comments challenging, inter alia, the PSC's jurisdiction over the cost allocation and cost recovery aspects of the projects referenced in the Joint Plan.[9]

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[4] See U.S. District Court for the District of New Jersey, Civil Action No. 11-745, PPL Energyplus, LLC, et al. v. Hanna, et al., slip opinion (dated October 11, 2013) (hereinafter "New Jersey Federal Court Decision").

[5] See November Order at 3.

[6] Case 12-E-0503, supra, "Compliance Filing of Consolidated Edison Company of New York, Inc. and New York Power Authority with Respect to the Development of Indian Point Contingency Plan" (filed February 1, 2013) (hereinafter, "Joint Plan"). The Joint Plan, inter alia: (i) sought authorization of, and associated cost recovery for, the development of three transmission projects ("TOTs Projects") and an incremental, 100 MW energy efficiency project (collectively, with the TOTs Projects, "TO Projects"); and (ii) proposed a structure under which NYPA would be requested to issue a request for proposals ("RFP") for alternative generation and transmission projects ("NYPA RFP Projects"), potentially enter into a contract(s) with RFP bidders and fully recover the costs of such contracts pursuant to PSC orders.

[7] Id. at 3-6.

[8] On February 13, 2013, the PSC issued a notice in the RCP Proceeding "clarifying" that the February 22, 2013 comments identified in the November Order were required to address, at a minimum, the proposed RFP to be issued by NYPA and further advising the parties that the PSC would be issuing additional notices on other aspects of the Joint Plan. (See Case 12-E-0503, supra, "Notice Soliciting Comments" (dated February 13, 2013).)

[9] See, e.g., Case 12-E-0503, supra, "Comments of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, Entergy Nuclear FitzPatrick, LLC and Entergy Nuclear Operations, Inc. Addressing the

On March 15, 2013, the PSC issued its first order to address the Joint Plan in which the PSC requested, inter alia, that NYPA issue an RFP for alternative new generation and transmission solutions to the TOTs Projects.[10] The PSC did not address the threshold jurisdictional issues that had been raised by parties to this proceeding in the March Order.

Thereafter, on April 19, 2013, the PSC issued its second order to address the Joint Plan.[11] In its April Order, the PSC determined inter alia, that initial planning work on the TOTs Projects should proceed on a preliminary basis which would be subject to "...a State rate recovery mechanism...to address the up to $10 million in preliminary planning costs for the TOTS projects...incurred prior to our anticipated September 2013 order."[12]

With respect to its identified State rate recovery mechanism, the PSC established that it "disagree[d] with New York City that we lack authority to develop a retail rate recovery mechanism that provides for the jurisdictional utilities to collect payments from their ratepayers for reliability-related activities" and that "this funding may be used to support actions taken by NYPA in support of their reliability-related activities undertaken in conjunction with the Indian Point Contingency Plan."[13] The PSC did not provide any citation for its determinations in its April Order. Finding that the Joint Plan's proposed cost allocation and cost recovery

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February 1, 2013 Proposed Joint Reliability Contingency Plan" (filed February 22, 2013) at 9, n.21; Case 12-E-0503, supra "Comments of the City of New York on the Indian Point Contingency Plan" (filed February 22, 2013) at 32.

[10] See Case 12-E-0503, supra, "Order Upon Review of Plan To Issue Request for Proposals" (issued and effective March 15, 2013) (hereinafter, "March Order").

[11] See Case 12-E-0503, supra, "Order Upon Review of Plan To Advance Transmission, Energy Efficiency and Demand Response Projects" (issued and effective April 19, 2013) (hereinafter, "April Order").

[12] See April Order at 10. The November Order expressly limited the scope of the PSC's directives to the development and filing of a contingency plan. The April Order specified that the approved preliminary planning activities did not include any construction-related activities. (Id. at 8.) Thus, to date, there has not been any PSC directive in this proceeding authorizing the development and construction of, and associated cost recovery under a State-based mechanism for, any TO Project or NYPA RFP Project. Importantly, the April Order acknowledged that the TOTs Projects were not needed if the Indian Point facility retains its NRC operating license. (See id.)

[13] Id.

mechanisms "require[d] further development and consideration," the PSC directed the Staff of the New York Department of Public Service ("DPS Staff") to issue a straw cost allocation/cost recovery proposal for comment.[14]

On June 4, 2013, DPS Staff filed its straw proposal in this proceeding.[15] The Straw Proposal stated that jurisdiction over "other types of regulated reliability solutions," such as to "address reliability deficiencies due to the potential Indian point shutdown," rested with the PSC.[16] DPS Staff did not provide any citations to support this statement.

In accordance with the Revised Straw Proposal Notice,[17] a number of parties submitted comments establishing, inter alia, that the FERC had exclusive jurisdiction over these cost allocation and cost recovery matters, and thus, the PSC was proscribed from adopting the Straw Proposal on jurisdictional as well as other grounds.[18] Thereafter, acting in accordance with the Revised Straw Proposal Notice, several parties submitted reply comments. No party challenged the jurisdiction analyses in their respective reply comments.

The PSC has not yet issued an order addressing the Straw Proposal nor has it issued a final decision concerning the structure for its identified need for significant advanced planning in this proceeding. However, during the Consent Agenda portion of the September 19, 2013 PSC

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[14] Id. at 12.

[15] See Case 12-E-0503, supra, "Straw Proposal for Indian Point Shutdown Regulated Reliability Cost Allocation and Cost Recovery" (dated June 4, 2013) (hereinafter, "Straw Proposal").

[16] Id. at pp. 1-2.

[17] See Case 12-E-0503, supra, "Notice of Second Technical Conference and Revised Comment Schedule" (issued July 2, 2013) (hereinafter, "Revised Straw Proposal Notice").

[18] See, e.g., Case 12-E-0503, supra, "Initial Comments of Multiple Intervenors on Cost Allocation and Cost Recovery on Straw Proposal and Draft Reimbursement Agreement" (filed July 22, 2013) at 7-9; Case 12-E-0503, supra, "Comments of the City of New York on the DPS Staff Straw Proposal for the Recovery of Indian Point Shutdown Costs and NYPA Draft Reimbursement Agreement" (filed July 22, 2013) at 4-5; Case 12-E-0503, supra, "Initial Comments of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, Entergy Nuclear FitzPatrick, LLC and Entergy Nuclear Operations, Inc. on DPS Staff's 'Straw Proposal for Indian Point Shutdown Regulated Reliability Cost Allocation and Cost Recovery'" (filed July 22, 2013) at 15-28.

session, PSC Chairman Audrey Zibelman stated that the PSC would act on this proceeding at its October 17, 2013 session. The RCP Proceeding is listed on the PSC's October 17, 2013 session agenda under the Regular Agenda Items – Power.

MOTION TO LODGE

On September 30, 2013, the United States District Court for the District of Maryland issued the Maryland Federal Court Decision.[19] In that proceeding, as here, jurisdictional challenges were raised concerning the Maryland Public Service Commission's authority to take certain actions involving facilities that participate in the wholesale competitive electric markets. Because the Maryland Federal Court Decision pertains to the threshold jurisdictional issues that have been raised in this proceeding and given the pendency of a possible final order in this proceeding, Entergy moved to lodge the Maryland Federal Court Decision into the record of this proceeding on October 4, 2013. Entergy's October 4th motion remains pending.

On October 11, 2013, the United States District Court for the District of New Jersey issued the New Jersey Federal Court Decision. In that proceeding, as here and in the Maryland federal court case, jurisdictional challenges were raised concerning the New Jersey Board of Public Utilities' authority to take certain actions involving facilities that participate in the wholesale competitive electric markets. Because the New Jersey Federal Court Decision also pertains to the threshold jurisdictional issues that have been raised in this proceeding and given the pendency of a possible final order in this proceeding, Entergy hereby moves to lodge the New Jersey Federal Court Decision into the record of this proceeding.

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[19] See U.S. District Court for the District of Maryland, Civil Action No. MJG-12-1286, PPL Energyplus, LLC, et al. v. Nazarian, slip opinion (dated September 30, 2013) (hereinafter, "Maryland Federal Court Decision").

CONCLUSION

For all of the foregoing reasons, Entergy respectfully requests that its motion be granted.

Dated: October 16, 2013
Albany, New York

Respectfully submitted,

GREENBERG TRAURIG, LLP

Doreen U. Saia

Doreen U. Saia
Counsel to Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, Entergy Nuclear FitzPatrick, LLC and Entergy Nuclear Operations, Inc.
54 State Street, 6th Floor
Albany, New York 12207
(518) 689-1400

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ATTACHMENT I

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF NEW JERSEY

PPL ENERGYPLUS, LLC, et al., Plaintiffs, v. ROBERT M. HANNA, in his official capacity as President of the New Jersey Board of Public Utilities, et al., Defendants.	Civil Action No.: 11-745 MEMORANDUM

SHERIDAN, U.S.D.J.

This non-jury case was tried before the Court over thirteen separate days in April and May, 2013. After trial, the parties submitted proposed findings of fact and conclusions of law as well as briefs, and thereafter, summations were heard. The Court, having considered the parties' submissions and having deliberated over the facts and the law, submits this memorandum as its decision.

In broad terms, the issue before the Court is whether the New Jersey Long-Term Capacity Pilot Project Act, P.L. 2001, c. 9, approved Jan. 28, 2011, codified at N.J.S.A. §§ 48:3-51, 48:3-98.2-.4 ("LCAPP" or "Act"), should be declared unconstitutional as violating the Supremacy Clause, and whether the New Jersey Board of Public Utilities ("NJBPU", "BPU", or as referred to herein as the "Board") should be enjoined from engaging in activities in furtherance of the Act because the LCAPP is preempted by the Federal Power Act, 16 U.S.C. § 824 *et seq*.. That is, whether actions by the State of New Jersey taken pursuant to the LCAPP intrude upon and interfere with the authority delegated to the Federal Energy Regulatory Commission (as referred to herein, "FERC" or "Commission") by the Federal Power Act.

Before proceeding to the substance of this case, the Court provides two cautionary observations regarding writing style and organization and a general reservation as to the presentation and scope of the findings within this decision. First, on writing style. The electric energy industry has its own jargon which makes great use of acronyms. With so many acronyms being used, the testimony and briefs become like alphabet soup where all the letters swirl around and may confuse the reader. As such, a list of acronyms which have been substantially agreed upon by the parties is attached as Rider A. The Court minimizes use of these acronyms in this decision. By way of reservation, the first part of the trial reviewed the extensive history of how the electric energy industry has developed into its present state. This opinion includes an overview of the relevant background for the purpose of providing sufficient information to decide the issues, however, it does not purport to be a historical work. And lastly on organization, there are many non-controversial facts presented within the Court's overview of the relevant background, and a new term may present itself without prior introduction. In this case, the term will be explained later in the Court's decision. After sifting through a confluence of facts, the Court has gleaned a set of manageable facts with which to evaluate the preemption issue. The decision is subdivided into several sections: (A) an identification of the parties to the action; (B) an identification of important non-parties; (C) an identification of witnesses who testified at trial; (D) a description of some basic facts regarding electricity; (E) background information on the electric energy industry; (F) a description of the "Reliability Price Model" ("RPM") process; (G) a description of the LCAPP statute; (H) an explanation of the impacts of the LCAPP; (I) a description of the credibility of witness; (J) analysis; and (K) a conclusion.

A. PARTIES TO THE ACTION

1. Defendants

New Jersey Board of Public Utilities. The defendants are Robert M. Hanna[1], Jeanne M. Fox, Joseph L. Fiordaliso, and Nicholas Asselta, all of whom are current or former commissioners of the New Jersey Board of Public Utilities[2]. Each is named in his official capacity against whom declaratory and injunctive relief is sought. Since each currently serves or formerly served as a commissioner on the Board, this opinion collectively refers to them as the "Board." The Board has broad statutory authority over the activities of public utilities within the State of New Jersey. *See In re Centex Homes, LLC*, 411 N.J. Super. 244, 254 (App. Div. 2009). Specifically, Title 48 of the New Jersey Statutes provides that the Board has "general supervision and regulation of and jurisdiction and control over all public utilities." N.J.S.A. § 48:2-13(a). As part of that authority, the BPU is authorized to require any public utility operating within the State to furnish safe, adequate, and proper service to consumer ratepayers at "just and reasonable" rates. N.J.S.A. § 48:2-21.

CPV Power Development, Inc. CPV Power Development, Inc. ("CPV") is an Intervenor/Defendant. CPV is a Delaware corporation that, through its subsidiaries, is engaged in the development, ownership, and management of natural gas-fired facilities in North America (T. 1587, 10-24). CPV owns and manages a natural gas-fired generation facility in Riverside County, California, and has taken steps to develop other natural gas-fired facilities, including

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[1] Mr. Hanna was named as President of the Board on December 21, 2011. At the time of the underlying facts, Lee A. Solomon served as Board President.

[2] In New Jersey, the Board has always been a distinguished public entity known for its practical and professional decision making. Over the years, many prominent New Jersey leaders have served on the Board. For example, Mr. Solomon and Mr. Asselta served in the New Jersey State Assembly. Both Governor Byrne and Governor Whitman have served as Board President. Moreover, William Hyland, a former New Jersey Attorney General who has served the State of New Jersey in many esteemed capacities, was a former Board President. In reviewing this matter, the Court has considered the Board and its members, their sound judgment, and their professionalism in furtherance of the public good.

projects in Maryland, New York and New Jersey. CPV began to develop its Shore Project in New Jersey prior to implementation of the LCAPP Act. (T. 1588, 6 through T. 1589, 17). Most importantly for purposes of this case, CPV was named an eligible generator under the LCAPP by the Board and cleared the RPM Auction on its 2012 bid (T. 1588, 15-22).

2. Plaintiffs

The Plaintiffs are a group of wholesale, retail, and marketing companies who produce and sell energy and are located within the PJM market[3]. Several Plaintiffs are identified below.

Plaintiff Calpine Corporation is an electric generation and marketing corporation with a number of subsidiaries. It is a publicly traded, independent power producer based in Houston, Texas which operates ninety-one (91) power plants throughout the United States and Canada. The Calpine generation companies are physically located in the PJM market and participate in the PJM wholesale energy and capacity markets.

Plaintiff Exelon Generation Company, LLC is a Pennsylvania corporation headquartered in Kennett Square, Pennsylvania. Exelon Generation is a wholly-owned subsidiary of Exelon Corporation. Exelon Generation's business consists of owning and operating electric generating facilities, wholesale power marketing operations, and competitive retail supply operations. Exelon Generation sells energy and capacity in the PJM interstate market and competes in PJM's wholesale capacity auctions.

The PPL Parties are a group of related companies principally located in Allentown, Pennsylvania which are market and generation subsidiaries of PPL Corporation. They are physically located in the PJM market and participate in the PJM wholesale energy and capacity

[3] Plaintiffs GenOnEnergy, NAEO Ocean Peaking Power, and Essential Power were never substantively discussed during trial and no injury was presented.

markets. Together they control or own about 19,000 megawatts of generating capacity in the United States, some of which is located within the PJM market.

Plaintiff PSEG Power, LLC is a Delaware limited liability company, headquartered in Newark, New Jersey. PSEG Power is a wholly-owned subsidiary of Public Service Enterprise Group, Inc.. PSEG Power owns approximately 11,850 megawatts of generating capacity within the PJM area, approximately 9,950 megawatts of which is located in New Jersey. PSEG Power sells energy and capacity at wholesale in interstate commerce, including in PJM's capacity and energy markets.

Plaintiff Public Service Electric and Gas Company ("PSE&G"), a subsidiary of Public Service Enterprise Group, is located in New Jersey and is one of the largest combined electric and gas companies in the United States. It is also New Jersey's oldest and largest publicly owned utility. PSE&G currently serves nearly three quarters of New Jersey's population from Bergen to Gloucester Counties.

Plaintiff Atlantic City Electric Company, based in New Jersey, is a subsidiary of Pepco Holdings, Inc., which provides electric service to approximately 547,000 customers in southern New Jersey. Pepco Holdings, Inc. is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 1.9 million customers in Delaware, the District of Columbia, Maryland and New Jersey.

B. OTHER IMPORTANT NON-PARTIES

The Federal Energy Regulatory Commission ("Commission" or "FERC") and PJM Interconnection, LLC ("PJM") are two entities that are key players in the sale and delivery of energy. The Commission and PJM are not parties to this action, but are discussed throughout this memorandum.

Pursuant to the Federal Power Act, 16 U.S.C. § 824 *et seq.*, the Commission has federal statutory authority to regulate the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. (Stipulated Facts ¶ 5). In this case, the scope of the Commission's jurisdiction in regulating the sale of electric capacity in the wholesale market, and whether such jurisdiction is exclusive or concurrent with the Board's jurisdiction, is at issue. The applicable federal statute from which the Commission derives its authority reads:

> (b) Use or sale of electric energy in interstate commerce.
>
> (1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter. 16 U.S.C. § 824(b)(1).

PJM Interconnection, LLC is a voluntary association of different energy stakeholders which includes administrative bodies and electric generators.[4] (Stipulated Facts ¶ 13). PJM is primarily subject to Commission regulation through a tariff. It operates a regional wholesale

[4] PJM was not well defined at trial. The issue of how these competing companies and regulatory bodies interact in terms of governance and voting procedures was not adequately addressed by any of the litigants.

market that includes all or part of thirteen states including New Jersey. In addition, PJM is a regional transmission organization ("RTO"). (T. 47, 17 through T. 48, 11).

PJM was originally founded in 1927. The name "PJM" is the brainchild of its earliest members who were from the states of "Pennsylvania (P), New Jersey (J), Maryland (M)". (T. 410, 22 through T. 411, 8). It was formed as a "power pool" for traditional utilities which recognized that a regional transmission organization could easily accommodate sharing of electric capacity more efficiently (T. 39, 5-10). The sharing of electrical capacity through such arrangements drastically drops consumer costs by limiting the number of electrical generation facilities required for peak hour production. As noted above, PJM operates pursuant to a tariff filed by PJM with the Commission called the "Open Access Transmission Tariff." (Stipulated Facts ¶ 23).

PJM has been a relatively successful operation. For instance, today, PJM is the "largest centrally dispatched power market . . . in the world," covering 60 million customers and 185,000 megawatts. (T. 69, 20 through T. 70, 1). Within PJM there are over 1,300 power plants and approximately 56,000 miles of transmission lines. (T. 406, 24 through T. 407, 11). Mr. Massey testified that PJM is the most sophisticated of all of the regional transmission organizations. In fact, "there are government officials and market participants from around the world that regularly travel to PJM for briefings about how the markets work. So [it is] considered state of the art." (T. 70, 1-8).

Gradually, the traditional utilities within PJM transferred operational control of all their transmission to PJM. Currently, PJM is responsible for "[m]anaging a regional transmission grid encompassing all or part of thirteen states and the District of Columbia." (Stipulated Facts ¶ 11).

PJM, under the supervision of the Commission, is "responsible for planning the electric system to preserve the reliability of the electricity supply" in New Jersey. (Pl.'s Ex. 45, at 27). That is, PJM "plan[s] expansions to transmission to improve the ability to transmit energy from where it is generated to serve load." (Stipulated Facts ¶ 11). Most importantly, PJM is also responsible for the "dispatching" of generation in real time. It does this from "a very sophisticated control room in Valley Forge, Pennsylvania . . . which looks like an air traffic control system." (T. 50, 6-13). From this control room, PJM "direct[s] this generator[], to ramp up [and] . . . to ramp down all in real time. Because over this 13 state area they must insure that supply and demand are matched almost perfectly in real time." (T. 50, 12-13). Despite these functions, PJM has no authority to construct or build a power plant, and likewise it has no authority to retire antiquated power plants. (Def.'s Ex. 183).

C. TESTIFYING WITNESSES

There were a number of witnesses who testified at trial, each of whom is identified below. All of these witnesses were very professional and proficient in their careers, and the Court weighed their credibility in light of these qualifications.

1. Plaintiffs' Witnesses

William L. Massey obtained his Law Degree from the University of Arkansas School of Law in 1973, and later earned an LLM from Georgetown University Law Center in 1985. Upon his law school graduation, he clerked for the U.S. Circuit Court of Appeals for the Eighth Circuit. He later became Chief Counsel for U.S. Senator Dale Bumpers of Arkansas, where he focused on energy matters before the Senate Committee on Energy and Natural Resources. President Clinton later appointed Mr. Massey to be a Commissioner of the Commission where he served for over ten years. Mr. Massey currently serves as a partner in the Washington, DC office of the law firm Covington and Burling and is an Adjunct Professor at the Georgetown University Law Center. Mr. Massey was qualified as an expert "in the history and evolution of the electricity industry." (T. 23, 12-15).

Joseph Dominguez is the Senior Vice-President for Governmental and Regulatory Affairs and Public Policy for Exelon Corporation. He obtained a Bachelor of Science Degree in Mechanical Engineering from the New Jersey Institute of Technology and a Law Degree from Rutgers University School of Law. He previously worked at the law firm of White & Williams in Philadelphia, Pennsylvania and served as an Assistant United States Attorney in the Eastern District of Pennsylvania.

Robert D. Willig, Ph.D. is a Professor of Economics and Public Affairs at Princeton University. Professor Willig studied mathematics at Harvard College and later obtained a Masters of Arts in Operations Research and Statistics, and a Doctorate in Economics from Stanford University. Professor Willig previously worked at Bell Labs performing research on the theory of economic regulation of regulated industries. After working there for five years, he became a Professor of Economics and Public Affairs at Princeton in 1978. Professor Willig's specialty is industrial organization which involves the interrelationships between business, technology, the marketplace, and government. He was qualified as an expert in the fields of economics and regulatory policy with particular expertise in electric energy. (T. 623, 21-25).

Michael Cudwadie is employed by PPL Energy Plus as Vice-President of Trading East. In that role, he is responsible for the hedging and trading activities of 9,000 megawatts of generation in the PJM markets. He has a Bachelor's Degree in Accounting from Pennsylvania State University, and an MBA from Lehigh University.

Zamir Rauf has been employed by Calpine Corporation as its Chief Financial Officer since 2008. In that role, he is responsible for the accounting and treasury functions of Calpine which include project finance, investor relations and risk management.

Daniel Cregg is the Vice-President of Finance for PSEG Power within PSEG Services Corporation. In this role, he develops business plans and near term earnings forecasts, prepares forecasts of market direction and analyzes elements of major investment decisions. He has a Bachelor's Degree in Accounting from Lehigh University and an MBA from the University of Pennsylvania's Wharton School of Business.

Anthony Robinson is employed by PSE&G as Director of Basic Generation Service and Basic Gas Supply Service. He has a Bachelor's Degree in Economics, Applied Math and Statistics from Stoney Brook University. (T. 939, 14-17).

2. Defendants' Witnesses

James P. Giuliano is Director of the New Jersey Board of Public Utilities' Division of Reliability and Security. He is responsible for natural gas pipeline safety, underground damage prevention and emergency management and security. He has a Bachelor's Degree in Communications, and has completed many state certifications in courses related to his job.

Oden Sherman Knight is the Senior Vice President of Marketing and Organization at CPV where he manages power sales and gas purchases. (T. 1584, 16). He has a Bachelor's Degree in Mechanical Engineering from Stanford University and a Masters in Business from Columbia University (T. 1584, 4-7).

Craig R. Roach is a principal of Boston Pacific Company, a consulting firm which focuses on power plant development. He has a Bachelor's Degree in Economics from John Carroll University and a Doctorate in Economics from the University of Wisconsin. Mr. Roach was qualified as an expert in the design and implementation of competitive procurements and competitive markets for electricity.

Mr. Richard L. Levitan was the Board's advisor for implementation of the LCAPP. He has served as President of the consulting firm Levitan & Associates since its founding in 1989. The firm provides management consulting and analytic expertise to regional transmission organizations and short form independent system operators. He is a graduate of Cornell University and received a Masters with a specialization in Energy Economics from Harvard University.

D. BASIC FACTS REGARDING ELECTRICITY

Energy is "the actual electricity" that electric generators produce and which residential and business consumers ultimately use[5]. (Stipulated Facts ¶ 20). It cannot be stored in quantities large enough to supply customers during times of peak demand. (*Id.*). That is, energy cannot be canned or placed in a battery for a long period of time. It has no shelf life. As a result, "energy generally must be produced when it is needed, and at the rate at which it is consumed." (*Id.*) As Mr. Massey stated during his testimony, "[o]ne of the things about electricity is that it cannot be easily stored, and so supply and demand have to be matched instantaneously in real time." (T. 35, 4-6).

Energy is a product in interstate commerce. Regardless of which generator dispenses the energy, it ordinarily travels through interstate commerce to reach its destination. In 1927, the Supreme Court held that the interstate commerce clause prohibits states from regulating the rates for wholesale energy sales between utilities in different states because those sales are interstate transactions. *Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927); (Stipulated Facts ¶ 4). Surprisingly, no witness precisely described the logistics of an energy

[5] Residential and business customers are often referred to as "consumers" or "ratepayers".

delivery transaction (i.e., how energy is transmitted from a generator to a consumer) except to say that the delivery of energy is overseen by PJM and PJM routes energy through its transmission system. (T. 50, 6-13)

Amount of Energy. Energy is usually measured in megawatts. One megawatt of electricity powers approximately 1,000 households. Usually, megawatts are associated with lengths of time such as "per day" or "per hour." (Stipulated Facts ¶ 18).

Capacity. "Capacity" is defined as "the ability to produce electricity when called upon." (Stipulated Facts ¶ 17). In essence, capacity is the ability to produce sufficient energy to meet demand. At certain times, such as during the summer months when temperatures increase, demand for energy increases. Regardless of fluctuations, there must be sufficient capacity to meet the demand of high energy use at all times.

Capacity Resources. "Capacity resources include electric generation facilities (e.g., nuclear, natural gas, coal, wind, or solar), demand resources (i.e., the ability to call upon consumers to reduce their electricity demand), and energy efficiency resources (measures that reduce demand)." (Stipulated Facts ¶ 19).

Reliability. "Reliability" is the delivery of electricity to customers in the amounts desired and within acceptable standards for frequency, duration and magnitude of outages and other adverse conditions or events. (T. 81, 23 through T. 83, 12). According to Mr. Levitan, electric reliability means being able to "keep consumers' lights on" under duress and maintaining the power system when operating contingencies arise. (T. 1549, 8-11); *see also* I/M/O the Petition of Public Service Gas and Electric Company for a Determination Pursuant to the Provisions of N.J.S.A. 40:55D-19 (Susquehanna-Roseland Transmission Line). Resource adequacy is a key component of reliability. (T. 1549, 6-14). The key factor in meeting the reliability standard is having sufficient generators and transmission lines available to deliver energy as required by the circumstances.

Generation Plants. Generation plants are categorized into three types – base load, mid-merit, and peaking plants. The parties agree on the definition of base load and mid-merit. A base load plant is a plant that operates all or most of the time. A mid-merit plant, such as a combined-cycle gas turbine, is a plant that operates less than a base load plant but more than a peaking plant. The parties disagree on the definition of a peaking plant; but generally, a peaking plant is "a gas turbine, a simple cycle unit, a unit that is typically run sparingly, a unit that has certain technology characteristics that allow it to get started from a cold stand-by mode, and achieve full operation in just a few minutes." (T. 1289, 12-16).

E. BACKGROUND OF THE ELECTRIC ENERGY INDUSTRY

In the beginning of the twentieth century, the New Jersey Legislature, like many other state legislatures at the time, enacted a statute creating a public utility to oversee the operation of electric and gas utilities. During the early stages of utility regulation, states had exclusive authority over such utilities. During this time, the energy industry "was dominated by vertically integrated utility companies" (hereinafter, referred to as "traditional utilities")[6]. (T. 24, 24 through T. 25, 1); (Stipulated Facts ¶ 1).

Typically, the traditional utility was granted an exclusive right by state and local governments to provide electric service to all consumers located in a defined territory. The traditional utility also had other powers, such as eminent domain authority, that would allow it to construct and operate power plants and local distribution networks to connect those power plants to local customers. In return, the traditional utility obligated itself to operate as a "common

[6] The parties refer to the traditional utility as a "vertically integrated utility." For purposes of minimizing confusion, this memorandum uses the term "traditional utility" because the word "utility" is now associated with an electric distribution company (EDC).

carrier" with the duty to provide service on a non-discriminatory basis, and to subject its rates to regulation by a state public utility commission. The regulatory standards adopted by state commissions permitted rates that would reimburse utilities for their costs incurred in providing service and debt incurred in financing the construction of power plants and other equipment. The standards were also meant to afford investors in these utilities a reasonable rate of return. This structure enabled the traditional utility to raise capital through the issuance of stock or selling of debt, which, in turn, would allow the utility to expand its facilities. Recovery of and on an investment in a traditional utility, however, was always subject to a “prudence review” by the Board in New Jersey. (Stipulated Facts ¶ 2).

In 1927, the Supreme Court of the United States decided the landmark case *Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927). In that case, the Public Utilities Commission of Rhode Island attempted to regulate the sale of electricity from the Narragansett Electric Lighting Company to the Attleboro Steam & Electric Company located in Massachusetts. The Court struck down the Public Utilities Commission of Rhode Island’s efforts deeming that its regulation had placed a direct burden on interstate commerce. The Court’s decision ultimately created a regulatory gap wherein no regulator had the authority to oversee interstate transactions made by traditional utilities.

In 1935, envisioning that the federal government should have a role in regulating interstate energy transactions, Congress enacted the Federal Power Act, which gave the Commission exclusive regulatory authority over “the transmission of electric energy in interstate commerce” and “the sale of electric energy at wholesale in interstate commerce. 16 U.S.C. § 824(b). While the statute vested this authority in the Commission, it also “reserved to the States certain . . . regulatory authority, including that over generation facilities.” (Stipulated Facts ¶ 5).

Under the statute, state commissions "continued to regulate local utilities' construction of new power plants, operations, and rates charged for retail service to customers" including "the costs incurred by local utilities in constructing and operating the power plants they used to generate electricity to service their retail customers. (*Id*.) From 1920 until the late 1980s, utilities operated under the concurrent supervision of both federal and state regulations. During that time, the Board and Commission acted cooperatively and respected their jurisdictional limits.

Before the advent of federal authority in the electric power industry, a traditional utility "performed three main operational tasks: it built, owned, and operated electric power plants; it transmitted electricity from the power plants to the area of service in which it enjoyed a monopoly; and it distributed the electricity to its customers in that area of service using its local distribution network, that is, the poles and wires that it owned and maintained." (Stipulated Facts ¶ 1). Each traditional utility was, in essence, a "single company" that "generated power, transmitted that power, and distributed that power to its own customers, the homes and businesses that it serves". (T. 2008, 13-18). In these early years, there was little to no relationship among the traditional utility companies, so each company generally only produced sufficient capacity to service its own customers' needs. Each traditional utility had a service territory established by state regulation, a monopoly for electricity service within that territory, and an obligation to serve all customers in that service territory. "[I]n return for fulfilling that obligation to serve all customers, [traditional utilities] were given an assurance of a reasonable rate of return." (T. 27, 16-21); (Stipulated Facts ¶ 2). As a result, a traditional utility's sales of electricity to residential and business users within its service territory were considered retail sales to consumers and "largely regulated at the state level." (T. 25, 5-6); (T. 30, 12-13); (Stipulated Facts ¶ 5).

Often the lack of interaction among traditional utilities created inefficiencies because each utility would construct its own power plants to meet peak electric demand; that is, each traditional utility "was insuring that it had enough capacity to serve its own load." (T. 37, 16-18). Because electricity demand peaks at limited times throughout the year, a utility may have needed to build a power plant that runs only "10, 15, 20, 50 hours a year." (T. 35, 3-13). As a result, each traditional utility tended to have "plants that [were] sitting idle most of the time, because they [were] needed for a few hours." (T. 37, 16-24). "[T]hat created some inefficiencies in the sense [that] . . . too many power plants to provide this capability were being built." (T. 37, 16-24).

In the early twentieth century, some electric utilities smartened up, adjusted their strategy, and "began to sell power or standby capacity to each other." (Stipulated Facts ¶ 3). In order to accomplish this, the traditional utilities "built high voltage transmission lines among them in order to transact such 'wholesale' purchases and sales. This allowed utilities to lower costs because they no longer had to maintain sufficient capacity to supply peak demand at all times; instead, they could contract bilaterally in the interstate wholesale market to ensure that they had access to sufficient resources to supply peak demand when it was needed." (Stipulated Facts ¶ 3). Thereafter, to protect against outages, traditional utilities would buy and sell capacity from one another for future years, so that they could be assured they would have sufficient supply when operating contingencies arose, without having to develop more power plants.

As the traditional utilities engaged in increased wholesale sales and capacity purchases, the need for federal regulation became more obvious. In order to manage stand-by capacity sales, PJM was created to ensure reliability by managing interstate transmission lines and, in more recent years, by designing and operating wholesale auctions.

Deregulation of Wholesale Energy Sales by the Commission

In the 1980s, when governmental deregulation of business entities was a prevalent feature of federal policymaking, some federal legislators brainstormed that the structure for sales of energy and energy capacity could be modified from one in which sales were made at a governmentally imposed rate to one that was more economically efficient, competitive and based on the economic theory of supply and demand. This idea ultimately culminated in several initiatives during the 1990s.

In 1992, Congress enacted the Energy Policy Act of 1992 ("EPAct"), Pub. L. No. 102-486, 106 Stat. 2776, which authorized the Commission to ease restrictions on access to interstate transmission wires. This allowed more electric generators to provide energy to a broader area, and recognized the concept of separating generation facilities from other parts of traditional utilities. That is, the generation segment of a traditional utility could operate separately from the other segments of the utility. A key objective of the Energy Policy Act was to "encourage[e] the development of independent generators" – sometimes referred to as "independent power producers" – "that could sell into the marketplace." (T. 44, 11 through T. 46, 25).

In 1996, the Commission issued Order Number 888 which required "transmission owners in the United States . . . to offer access to their transmission wires to third-parties . . . on a non-discriminatory basis." (T. 45, 12-19). "Order 888 opened the transmission grid, and competition began to develop, and . . . . wholesale markets were actually emerging regionally." (T. 47, 12-16). In 1996, through Orders 888 and 889, the Commission "established national open-access rules that required all transmission-owning utilities under its jurisdiction- i.e., those utilities that 'own, control, or operate transmission facilities used for transmitting electric energy in interstate transmission' - to provide non-discriminatory transmission access under standardized tariffs. One significant impact of Orders 888 and 889 was to increase the opportunity for non-utility generators to sell their power to additional markets." (Stipulated Facts ¶ 8).

In December 1999, the Commission issued Order 2000 which encouraged industry participants to organize themselves into large regional entities called regional transmission organizations ("RTO"). The creation of such organizations "allow[ed] for regional operation of the transmission system and provide[d], among other things, a platform for regional wholesale electricity markets." (Stipulated Facts ¶ 9). Notably, PJM is an RTO.

PJM adapted some of its functions to meet the requirements of these statutes and regulatory directives. Most importantly, PJM instituted three types of wholesale markets: "[the] capacity market, the energy markets and the ancillary services markets." (T. 74, 21 through T. 75, 23). Each of these markets has a special function:

(a) the "regional capacity market, called the reliability pricing model (RPM), annually sets the price of capacity" three years forward. The controversy in this case involves the regional capacity market. (T. 74, 23-24).

(b) the energy markets price the cost of energy produced by the generators and used by consumers. (Stipulated Facts ¶ 20). PJM operates a "day ahead" energy market, meaning "generators offer to supply power into the market a day ahead of real time." The day ahead market is a "planning tool that PJM uses to [e]nsure that it knows a day ahead of time what resources are going to be available 24 hours thereafter, when the generation is actually dispatched to keep the lights on." PJM also operates a "real time energy market, which is an hourly market that is close to the time of operation. And capacity resources bid into that market, and offer to supply . . . the actual electricity." (T. 74, 21 through T. 75, 23); and

(c) the ancillary services markets price the sale of "ancillary services" such as "spinning reserves and load-following services" to improve reliability. (T. 74, 21 through T. 75, 23).

Deregulation of Electric Generators by the Board

Following the federal lead, many traditional utilities chose to restructure by separating their generation functions from their transmission and distribution functions. (Stipulated Facts ¶ 6). According to Mr. Massey, there were two methods to accomplish this. First, the traditional utilities could sell or transfer their power plants to a competitive generation company. Second, the traditional utilities could "create an affiliate corporation . . . within a holding company to own the generation." (T. 53, 13-21). During the 1990s, many states restructured their electric industries to promote competitive markets in wholesale power generation. "Typically, the [s]tate-ordered restructuring resulted in the unbundling of [traditional] utilities into separate generation, transmission, and distribution companies. The distribution entities came to be known as 'Electric Distribution Companies' or 'EDCs[.]'" (Stipulated Facts ¶ 6). In some cases, "restructuring also enabled third parties with no distribution assets to compete in the sale of electricity at retail." (*Id*.) These entities are referred to as "Load Serving Entities" ("LSEs") (*Id*.).

In 1999, New Jersey followed suit. It restructured its utilities in a slightly different format than described above, but with the same result. In enacting the Electric Discount and Energy Competition Act ("NJ Energy Competition Act"), N.J.S.A. § 48:3-49 *et seq.*, the New Jersey legislature unbundled the sale of energy to retail customers. The consumer could choose to be served by one of several load serving entities which would compete to provide service. These LSEs would deliver the energy through an electric distribution company ("EDC"). (T. 59, 2-9). As Mr. Dominguez explained in his testimony, the driving force behind the NJ Energy

Competition Act was "customer choice" – that customers would have the right to choose their electricity suppliers or LSE. (*Id.*) Although the New Jersey Legislature focused on the benefit to the consumer, the NJ Energy Competition Act also "required the State's [traditional] electric utilities to divest themselves of electricity generation assets." (Stipulated Facts ¶ 7). Once the generation component was stripped, the word "utilities" became associated with the term "electric distribution companies" because EDCs were responsible for distributing electricity over local distribution networks to consumers in monopolistic service areas and were required to act as common carriers.[7] "The electricity itself was supplied by retail electric suppliers, that is, LSEs." (Stipulated Facts ¶¶ 7, 9).

At the time of enactment, the New Jersey Legislature recognized the magnitude of this fundamental change by declaring that "this bill would effectively end the system of government regulation of the electricity generation industry, which has existed in New Jersey since the years when Woodrow Wilson served as Governor." Electric Discount and Energy Competition Act, P.L. 1999, c.23. eff. Jan. 25, 1999. Hence, the NJ Energy Competition Act recognized the demise of the traditional utility and the transformation of the electric energy industry into a more market driven system. Further, although the federal and state statutory amendments opened new competitive markets through restructuring, the State retained its authority over the siting and construction of power plants. (T. 167, 9 through T. 169, 6). So, after restructuring by the federal and New Jersey governments, the electric energy industry operates in the following manner:

(a) generators may sell energy and capacity at wholesale prices to PJM or negotiate power supply agreements (T. 64, 11 through T. 65, 4);

(b) PJM transmits and sells energy to load serving entities ("LSEs"); and

[7] The electric distribution company is referred to as a utility, but its operation is not as expansive as a traditional utility.

(c) LSEs sell to consumers and distribute the energy through electric distribution companies ("EDCs") which have monopolistic service areas and operate as common carriers. Since the EDC transmits the electric to consumers within its monopolistic area, it receives a delivery fee from the LSE.

In New Jersey, there are four EDCs: Rockland Electric Company, Public Service Electric & Gas Company ("PSE&G"), Jersey Central Power & Light Company ("JCP&L"), and Atlantic City Electric. (Pl.'s Ex. 45, at 16-17). Each EDC owns and operates the local distribution wires located within its service territory. (T. 66, 17-22). After the restructuring, the State's utilities "became more commonly known as 'electric distribution companies' ('EDCs') because they were responsible for distributing electricity over local distribution networks." (Stipulated Facts ¶ 7). An EDC is sometimes referred to as the "local utility," but "the term EDC, electric distribution company, is intended to convey that this company is in the business of delivering electricity." (T. 56, 6-12). The electricity sold to retail customers by LSEs is delivered by the EDC within their local distribution networks.

The 2008 New Jersey Energy Master Plan authorized by the Board summarized the importance of the NJ Energy Competition Act:

> The owners of New Jersey power plants now have no legal expectation that they can recover all of their costs or a guaranteed return from retail customers. Hence, the plant owners (and their financiers) make their own decisions to invest in existing or new power plants, without [Board] oversight. They also make their own decisions about the price, using market signals, at which they are willing to sell their electricity, without traditional [Board] oversight. (Pl.'s Ex. 45, at 16).
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> PJM, under the supervision of [the Commission], is responsible for planning the electric transmission system to preserve the reliability of the electricity supply in its territory. Electric generation companies and their financiers make decisions about how much generating capacity will be

> built, what types of power plants will provide that new capacity, and where the new plants will be located; those companies also decide what plants will be kept in service and what plants will be retired. Those decisions are informed by economic signals from the wholesale electricity markets that PJM designs and administers, again under the supervision of the [Commission]. (*Id*. at 27).

Despite deregulation which provided generators with more decision making powers, the Commission and PJM do not have substantial authority to require construction of power plants, prevent retirement of generation, select the generation technologies that will be constructed, or require demand resource or energy efficiency programs as a means of addressing resource adequacy. (Def.'s Ex. 563). However, as previously noted, the restructuring of the traditional utilities required PJM and the Commission to institute three competitive markets which effect energy and capacity prices. The market of primary interest in this case is the regional capacity market called the reliability pricing model ("RPM").

F. THE RELIABILITY PRICING MODEL ("RPM")

The RPM is intended to "secure sufficient capacity resources to meet standards for serving the highest aggregate demand of the region's electric customers." (Stipulated Facts ¶ 12). To meet that objective, the RPM "establishes an annual Base Residual Auction ('BRA') [or "RPM Auction"] through which PJM administers procurements of capacity." (*Id*.)

The RPM conducts the RPM Auction each May to secure the capacity that will be needed three years in the future. (T. 419, 3-8); (Stipulated Facts ¶ 25). New Jersey is a voluntary member of PJM and is a part of the RPM market. (Stipulated Facts ¶ 13). RPM is a provision of the PJM tariff which is approved by the Commission. (Stipulated Facts ¶ 23); (T. 80, 25 through T. 81, 4); (Def.'s Ex. 184). As the parties stipulated:

> Through the [RPM Auction] PJM seeks to procure . . . the amount of capacity that it has determined . . . will be needed to meet the system (or in some cases, the Locational Deliverability Area ('LDA')) peak three years in the future, plus a reserve margin. PJM then bills each participating load serving entity for its load-ratio share of the costs incurred by PJM to secure that capacity through the [RPM Auction]. (Stipulated Facts ¶ 26).

Generally, "The [RPM Auction] is a 'forward market,' meaning capacity is sold three years in advance of when it is needed. For example, the auction held in May 2012 [which is the subject of this lawsuit] concerned offers to sell capacity to be 'delivered' beginning June 1, 2015, through May 31, 2016." (Stipulated Facts ¶ 27).

RPM was designed to provide price signals for both new and existing generation. PJM Interconnection, LLC, 132 F.E.R.C. ¶ 61,173, 61,870 (2010). The Commission has emphasized that "RPM was designed to provide long-term forward price signals, and not necessarily long-term revenue assurance for "generators and developers." (Pl.'s Ex. 55, at 55-56). As Mr. Dominguez stated, "the RPM is a market-based mechanism that uses economic price signals to indicate scarcity and need for capacity," and generators will decide from the price signal whether or not to expand or create new generation. (T. 413, 1-8).

"In the [RPM Auction] capacity resources . . . bid to supply capacity to PJM for one year beginning three years in the future, each offering to supply a particular quantity of capacity at an offer price." (Stipulated Facts ¶ 28). The bids of capacity resources are "stacked" from lowest-cost bids to highest-cost bids to construct a supply curve. (T. 92, 19-25). PJM also constructs a demand curve that is based on a forecast of peak electricity demand ("peak load"), plus a reserve margin. (T. 661, 13 through T. 662, 19). The PJM "reserve margin" is typically around 15 percent or more. The reserve margin addresses the possibility that "some plants might fail, might not be able to meet their obligation," or that there could be a "transmission outage." (T. 89, 25 through T. 90, 13). As Mr. Massey indicated, "[i]t also takes into account the fact that . . . [it is]

hard to forecast electricity usage perfectly." (T. 90, 2-3). "And so this reserve margin is an insurance policy." (T. 90, 7). "The price of capacity in the [RPM Auction] is set by the intersection of supply and demand and is referred to as the 'clearing price.' That is, any capacity supplier that bids at or below the clearing price 'clears' the [RPM] auction and receives the clearing price for that capacity. Any capacity supplier that bids above the clearing price fails to 'clear' the [RPM] auction, and its capacity does not sell in the auction." (Stipulated Facts ¶ 29). The clearing prices for capacity sold in the RPM are the Commission approved rates for capacity sales made in PJM territory. (Pl.'s Ex. 26). When a generation resource has cleared the auction, it obligates itself to run through the delivery year. (T. 473, 22 through T. 474, 7). Thus, a capacity resource that clears the RPM Auction commits itself to make any investments necessary to fulfill its obligation. It also obligates itself to bid into the PJM energy and ancillary services markets. (T. 426, 1 through T. 473, 17).

As Mr. Dominguez testified, RPM is designed to procure the least expensive mix of resources that are necessary to keep the lights on for that one year period, three years hence. (T. 414, 14-18). Generally, the RPM Auction says to market participants "I am willing to serve capacity for one entire year three years forward." (T. 414, 14-18). "The purpose" of RPM was to "guarantee[] that the reliability target in PJM is met in the least cost possible way." (T. 763, 13-23). As PJM has explained to the Board, its "RPM Capacity Market is designed to commit the least-cost set of capacity resources to ensure that [Commission]-established resource adequacy targets are met in the PJM footprint on a three-year forward basis." (Pl.'s Ex. 230, at 10).

Generally, the single clearing price encourages capacity resources to operate more efficiently while keeping prices low. "[A] competitive market with a single, market-clearing price creates incentives for sellers to minimize their costs, because cost-reductions increase a seller's profits. And when many sellers work to minimize their costs, competition among them keeps prices as low as possible. . . . This market result benefits customers, because over time it results in an industry with more efficient sellers and lower prices." PJM Interconnection, LLC, 117 F.E.R.C. ¶ 61.331, 62678 (2006); (Pl.'s Ex. 19, at 57); (T. 436, 8-24). As Mr. Massey indicated, since there is a single price for the commodity, "the person who can provide the [capacity] cheapest will do the best in that market; [and the] person who cannot provide the [capacity] competitively is either going to go out of business or figure out how to do better." (T. 436, 19-24). Mr. Massey explained "economists would say it's the law of one price. . . . It [does not] matter whether the electric energy's produced by an old generator [or] new generator, [it is] electric energy, it has the same value in the marketplace. And that [is] why pursuant to [Commission] rules that single clearing price model is used." (T. 92, 19 through T. 93, 23).

Despite the goal of reaching a highly competitive price through the RPM Auction, price varies in certain areas of the PJM market. For example, in New Jersey the price is higher than that in western Pennsylvania because the transmission costs associated with delivering the energy in New Jersey are more costly. (Def.'s Ex. 204). "For purposes of the RPM, PJM is divided into regions known as [Locational Deliverability Areas, or] LDAs." (Stipulated Facts ¶ 30). "New Jersey is located in a Locational Deliverability Area called 'EMAAC,' which also includes parts of Maryland, Pennsylvania, and Delaware. EMAAC is located within a wider [LDA] called 'MAAC,' which includes EMAAC, additional parts of Pennsylvania and Maryland, and the District of Columbia." (Stipulated Facts ¶ 31). According to the parties, within EMAAC, "there are smaller LDAs, including (within New Jersey), one called 'PSEG', and within the PSEG LDA, another one called 'PSEG North.'" (Stipulated Facts ¶ 33). As the parties explained:

> When constraints on the transmission lines limit the amount of electricity that can be imported into an LDA, RPM capacity prices can be higher in the constrained LDA - reflecting the fact that the LDA must rely on more expensive capacity resources located within the LDA rather than cheaper capacity resources located elsewhere. (Stipulated Facts ¶ 33).

Prices are often different among the LDAs leading to "price separation." As the Commission has explained, "[c]apacity market prices must be locational in order to be fully effective. Because of transmission constraints, capacity in one location is not always deliverable to loads in other locations[.]" (Pl.'s Ex. 26, at 34). As such, separate capacity prices are necessary to reflect the differences in costs and capacity needs among the locations. "Further, if a single capacity price is set for the entire region, capacity prices do not reflect the need for generation" in those particular locations. (*Id*.) For instance, as Mr. Dominguez stated "higher price for capacity gives a signal to those in the generation industry to consider developing a new plant or resource within the LDA because a better profit could be realized." (T. 445, 24 through T. 446, 12). "[T]his price differential is reflective of the transmission constraints in moving power from west to east into New Jersey and [signals] the need for resources to be located inside New Jersey." (Pl.'s Ex. 75, at 7).

From its initial inception in the early 2000s, the Board did not accept the RPM theory. Rather, the Board predicted that RPM would curtail development of new generation into New Jersey. The Board recommended that new generators should be given assurances to overcome fears regarding the risk of long term financing packages of potential financiers. The Board also complained that the RPM functions unfairly against new generators. First, the Board argued that the long term price signals of the RPM Auction were insufficient to attract new generators in New Jersey since little development had occurred. (Pl.'s Ex. 197). Second, the Board argued that financial institutions were reluctant to loan money for development because of uncertainty. That is, capacity prices fluctuate and the clearing price of the RPM Auction only lasts a year ultimately rendering a long term loan very speculative. In reality, these variables caused energy prices to increase in New Jersey. As then-Board Commissioner Frederick Butler advised the Commission in February 2006:

> RPM, in its current form, will not have the intended effects on investment and will not result in the most cost effective means of solving future reliability problems. Thus, we are concerned that RPM, in its current form, will not ensure adequate electricity supply within New Jersey, and will lead to increased costs to our consumers. (Pl.'s Ex. 13, at 1).

Mr. Butler requested that the Commission undertake "additional dialogue . . . to shape the short term and long term needs of [the] wholesale electricity market[,]" rather than adopting the RPM. (*Id*. at 6). Notwithstanding New Jersey's policy objections, the Commission approved RPM because it disagreed with New Jersey's argument that "the [RPM] Settlement will raise prices without improving reliability." (Pl.'s Ex. 19, at 30); (T. 103, 11, through T. 104, 5).

In 2007, despite the Board's objections, the RPM rule was adopted which included the minimum offer price rule ("MOPR"). PJM subsequently adopted new rules on how the RPM would operate. These rules contemplated, among other things, who may enter into the RPM market and how each generator may bid (T. 2653, 2-8). Most notably, the MOPR governed biddings by new capacity resources. Over the last several years, the MOPR has been modified several times by PJM in 2011 and 2013. Some of these modifications occurred based on the facts of this case.

The RPM Auction is not based on a pure open bidding process. For instance, an existing generator which previously operated as a part of a traditional utility is permitted to bid at zero. (T. 1652, 23 through T. 1653, 2). The rationale for permitting such bids is that these generation facilities have been operating longer than projected so capital costs have been recaptured. As such, the capital costs are deemed to be zero.[8] The ability of these long time generators to bid at zero when they may have sufficient capacity to provide to PJM raises a question as to whether the RPM Auction is actually necessary. In response to this question, PJM developed the MOPR, which it administratively calculates each spring from costs associated with the entry of a new generator; and then it lists administratively determined amount as the net cost of new entry ("net cone"). PJM converts that net cone into a price of megawatts per day ("benchmark price") (T. 1662, 17-19). While existing generators still bid at zero, they are accepting the net cone benchmark price in the RPM Auction. Hence, an existing generator became commonly known within the industry as a "price-taker." If such a generator forecasted that the benchmark price would fall below its projected cost, that generator may choose not to bid and retire the plant. (Def.'s Ex. 235). However, PJM was also concerned that new generators would bid below the benchmark price in order to be accepted into the capacity market. Hence, MOPR was also a "mechanism that s[ought] to prevent the exercise of buyer market power in the forward capacity market by ensuring that all new resources are offered into PJM's Reliability Price Model (RPM) on a competitive basis." (Def.'s Ex. 331, at 4). In order to determine the competitiveness of a new generator, PJM applies a "MOPR screen." The MOPR screen has several components:

(i) a conduct screen (i.e., a benchmark price used to determine whether a sell offer may be competitively low and thus warrants mitigation upward (described below); (ii) an impact screen test that compares the capacity clearing price with and without mitigation; and (iii) an incentive test, or net-short requirement (designed to distinguish between sellers who are net buyers and may have incentives to depress market clearing prices below competitive levels and

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[8] Peculiarly, if a long time generator added more capacity to an existing plant, it may still bid at zero despite the development costs.

sellers of planned generation who may have incentives to increase market clearing prices above competitive levels. (Def.'s Ex. 331).

Several exemptions applied to the MOPR's application including the "state mandated" and the "unit-specific" exemptions. When the MOPR was initially adopted, there was an exemption from the MOPR requirements if the project was undertaken pursuant to a state regulation or mandate (T. 1654, 12-15). According to Mr. Knight, a state mandated entrant could bid as an existing generator – price taker, and "bid whatever they wanted to bid." (T. 1654, 18). In addition, there was a unit-specific exemption applying to new gas-fired generation. Such unit-specific exemptions permitted bids down to 80% of the benchmark price upon a showing that the net cone costs were at that level. Such a bid may be lower than the administrative benchmark price.

As noted above, the MOPR was changed through tariff modifications in 2011 (MOPR II) and 2013 (MOPR III). MOPR II eliminated the exemption that previously permitted developers of certain state-sponsored projects from bidding as "price takers." It also raised the "price floor" for new entrants' bids from 80% to 90% of PJM's benchmark price. (Def.'s Ex., at ¶¶ 24, 43, 66). According to Mr. Knight's testimony, in May 2013, the Commission further ruled that: (1) state-sponsored projects should be subject to the MOPR (which led the Commission to eliminate the "state exemption"); (2) the default MOPR level should be 100% of net cone; and (3) new projects should be allowed to demonstrate that their own projected costs will be lower than the benchmark price and should be able to pass a MOPR screen based on those projected costs. (MOPR III). (T. 1679, 20 through T. 1680, 3).

In addition to the MOPR screens, there was another accommodation for new entrants called the New Entry Price Adjustment ("NEPA.") (Def.'s Ex. 238). The NEPA provision was intended to make investments in new generation less risky. The NEPA assures developers of projects in local deliverable areas ("LDAs") that after their facilities become operational they will continue to receive, for a period of subsequent years, the capacity price of the RPM Auction that prevailed at their time of their entry. In 2006, concerns regarding how long the NEPA guarantee should operate were addressed by PJM and the Commission. PJM and FERC ultimately settled on a period of three years. (Def.'s Ex. 238). Despite the MOPR and NEPA adjustments, the RPM costs left New Jersey residents with higher electricity prices due to associated transmission costs. These higher costs displeased the Board.

In addition to the RPM, two other energy issues arose in New Jersey at this time which adversely affected the industry and its regulations. First, PJM forecasted that the amount of energy required for New Jersey would be greater than the state's transmission capabilities potentially leading to outages. Notably, PJM identified twenty-three (23) power transmission violations which were likely to threaten PSE&G customers. Generally, these violations were deficiencies in service and reliability. (Def.'s Ex. 563, at 24-30); (Def.'s Ex. 567, at 20). The other adverse issue which arose was the adoption of new environmental regulations requiring that coal-fired plants be retired unless renovations substantially reducing emissions were made. As a result of these new environmental regulations, the Board projected that the amount of capacity within the PJM territory, particularly the amount of capacity in New Jersey, would be significantly reduced. Both of these adverse issues are discussed below.

Lack of Adequate Transmission Capabilities

In 2010, PJM disclosed to the Board that reliability issues may arise due to insufficient transmission capabilities in New Jersey. According to the PJM: "Based on the latest studies performed by PJM and the transmission owners, PJM, PPL and PSE&G concluded that there are

23 potential electric reliability violations that are expected to occur beginning in 2012, and extending out through PJM's 15-year planning horizon of 2022." (Def.'s Ex. 565, at 12). These violations had the potential to cause brownouts or blackouts. Since the violations were projected to occur within two or three years, the Board became concerned about whether transmission capabilities could be improved in such a short period of time. PJM found that this reliability issue could only be addressed in one of two ways — increased transmission through the construction of the Susquehanna-Roseland transmission line ("Susquehanna Connection") or construction of additional generation in or near the location where the reliability violations would occur. (Def.'s Ex. 563, at 33). Given the difficulties associated with implementing either of these contingency plans in such a short period of time, from the Board's perspective, New Jersey was at risk. As Mr. Roach summarized, "this is really, to put it mildly [an issue that] . . . [got] their attention." (T. 1893, 22 through T. 1894, 2).

Environmental Issues

In 2008, newly imposed environmental regulations cast their shadow over the New Jersey energy industry when the federal and state governments partially prohibited coal-fired plants from being operated unless significant environmental modifications were made. At that time, federal environmental rules required 12 to 19 gigawatts of capacity in the PJM territory, which amounted to about 7 to 11 percent of all PJM generation, be retired or renovated. (T. 1612, 7 through T. 1613, 15). In addition, about a year later, New Jersey adopted the High Energy Demand Day Rule ("HEDD") which created a potential reliability issue by limiting the number of hours that certain electric generating units could operate. (T. 1897, 9-24). In short, from a resource adequacy or capacity perspective, the Board believed that New Jersey was vulnerable to the shutdown of 11,000 megawatts of coal-fired generation. (Pl.'s Ex. 127); (T. 1289, 22 through

T. 1290, 9);(T. 1896, 21 through T. 1898, 10). As Mr. Roach explained it, the Board thought, "I've got to put iron in the ground[.] I've got to get a new power plant locally to protect against these things." (T. 1894, 12-16).

G. INTRODUCTION OF THE LCAPP STATUTE

The Board undertook several measurers to address its concerns. First, the Board appealed the Commission's decision implementing the RPM and MOPR rules. Second, the Board worked with the New Jersey Legislature to develop a bill that would create new capacity resources closer to or within the State.

The Board's petition of review of the Commission's decision was summarily denied by the United States Court of Appeals for the District of Columbia. In its decision, the Circuit Court concluded "that the Commission had a substantial basis on which to conclude that the RPM was an appropriate tool for increasing reliability in electricity markets, that the RPM did precisely what it was intended to do, even during the transition period before the three-year lag could take effect, and that the price hikes in its wake were attributable to legitimate causes." *Md. PSC v. FERC*, 632 F. 3d 1283, 1286 (D.C. Cir. 2011). The Court did not specifically address the Board's or the State of Maryland's contentions regarding lack of reliability, the regional nature of increased capacity prices, or the impact of the newly implemented environmental regulations governing coal-fired plants. Rather, the court seemed to accept the Commission's determination that the "rates were just and reasonable" at face value. *Id*. at 1285.

On January 28, 2011**,** the New Jersey Legislature, with the Board's support, enacted the LCAPP Act which authorized the construction of several gas-fired generators in or near New Jersey. (Stipulated Facts ¶ 35). The purpose of LCAPP was "[t]o address the lack of incentives under the reliability pricing model" by fostering the "construction of new, efficient generation . .

. [to] ensure[] sufficient generation is available to the region, and thus the users in the State in a timely and orderly manner[.]" N.J.S.A. § 48:3-98(d)(2); (Stipulated Fact ¶ 36). In general terms, the LCAPP Act established a "pilot program," overseen by the Board, to issue "Standard Offer Capacity Agreements" ("SOCAs") to selected eligible generators. N.J.S.A. § 48:3-98.3. The statute requires New Jersey's four electric distribution companies ("EDCs") to enter such contracts with eligible generators and obligates these EDCs to pay any difference between the RPM Auction price and their actual development costs approved by the Board. N.J.S.A. § 48:3-98.3(c)(9). The LCAPP contemplated the awarding of SOCAs for 2,000 megawatts of generation capacity. It further directed that the selected LCAPP generators were to "participate in and clear the annual base residual auction [RPM Auction] conducted by the PJM . . . for each delivery year of the entire term of the agreement." N.J.S.A. § 48:3-98.3(c)(12). In addition, the statute directed the Board to conduct a competitive solicitation of capacity and required winning bidders to enter into SOCAs lasting no longer than fifteen years with the State's electric distribution companies (EDCs). N.J.S.A. § 48:3-98.3(c)(1)-(4); *see also* (T. 121, 7 through T. 122, 24). The main purpose of the legislation was to provide a transaction structure that would result in new power plants being constructed in the PJM territory that benefit New Jersey. The New Jersey Legislature was ultimately interested in ensuring that new resources were constructed in time to help mitigate the reliability risks discussed above. N.J.S.A. § 48:3-98.2(b); *see also* (T. 1368, 17 through T. 1377, 1)

More specifically, the LCAPP statute required:

- that the Board hire an agent to: (1) "assist the Board with the establishment of the LCAPP program; (2) prequalify eligible generators for participation in LCAPP; and (3) recommend to the Board the selection of winning eligible generators based on the net benefit to ratepayers of each eligible generator's offer price and term." N.J.S.A. § 48:3-98.3(b)(1)-(3);

- that the Board "establish criteria associated with the prequalification of eligible generators in the LCAPP through a showing of environmental, economic, and community benefits, and through a demonstration of reasonable certainty of completion of development, construction, and permitting activities necessary to meet the desired in-service date" N.J.S.A. § 48:3-93.3(c)(6); (Stipulated Facts ¶ 39);
- that an "eligible generator" be "a developer of a base load or mid-merit electric power generation facility . . . that qualifies as a capacity resource under PJM criteria and that commences construction after the effective date" of the LCAPP. N.J.S.A. § 48:3-51; (Stipulated Facts ¶ 40);
- that a "Standard Offer Capacity Price ("SOCP") mean "the capacity price that is fixed for the term of the SOCA and which is the price to be received by eligible generators under a [B]oard-approved SOCA[.]" N.J.S.A. § 48:3-51. This price represents the development costs of the new generation as approved by the Board.
- that selected eligible generators "participate in and clear the annual base residual auction" (RPM auction) for the sale of their capacity to PJM." N.J.S.A. § 48:3-98.3(c)(12); and
- that the Board order that New Jersey's four electric distribution companies (EDCs) – Public Service Electric and Gas, Atlantic City Electric, Jersey Central Power & Light and Rockland Electric Company "procure 2,000 megawatts of financially-settled SOCAs from eligible generation" for a period up to 15 years. N.J.S.A. § 48:3-98.3(c)(1),(9). The Board was further obligated to "establish a method and the contract terms for providing

for selected eligible generators to receive payments from the electric public utilities for the difference between the SOCP and the RCP multiplied by the SOCA capacity." N.J.S.A. § 48:3-98.3(c)(4).

With the LCAPP, the New Jersey Legislature and the Board concluded that they would have to act to increase electric generation in the State due to the fact that the Commission's policies were not creating new capacity. As Dr. Roach noted in his testimony, the LCAPP created "some tension" between the Commission and the Board. (T. 2034, 25 through T. 2035, 1). One area of tension is summarized in the LCAPP. Within the statement of findings, the Legislature noted that the New Entry Price Adjustment was insufficient. It stated:

> The PJM reliability pricing model could, through structural changes, provide necessary incentives, such as the expansion of the "New Entry Price Adjustment" mechanism for the construction of new capacity, including new intermediate and base load plants, by allowing new resources to qualify and receive a guaranteed capacity price for a longer period of time. However, the implementation of similar structural changes was previously denied by FERC and any future implementation is uncertain at this time. N.J.S.A. § 48:3-98.2(c).

More specifically, the legislative findings declared that the Board would "allow new resources to qualify and receive a guaranteed capacity price for a longer period of time" than the RPM permitted. *Id*.

In addition, Board President Lee Solomon, in a September 16, 2010 memorandum to Governor Christie, affirmed that the purpose of the LCAPP was to establish a "multiyear pricing supplement" that would provide the new LCAPP generators with a premium payment or "RPM" adjustment that would guarantee a LCAPP generator a payment to secure multi-year capacity revenue." (Pl. Ex. 84, at 2). President Solomon also emphasized that the three year NEPA guarantee would be expanded to 15 years.

Moreover, LCAPP mirrors or overlaps the RPM Auction procedure. For instance, LCAPP requires that the price within a SOCA must be expressed in a "price per megawatt day" which is the same standard used in the RPM. *Compare* N.J.SA. § 48:3-98.3(c)(2) *with* (Stipulated Facts ¶ 8) (stating that "the price of capacity in RPM is generally measured in dollars per megawatt-day ("$/MW-day")).

Between 2008 and 2012, the transmission, reliability and environmental issues evolved. That is, many of the Board's concerns had subsided through the deliberate actions of PJM stakeholders and/or economic circumstances. As Mr. Roach characterized it, New Jersey "dodged a bullet." (T. 1894, 23 through 1895, 7). For example, PJM's reliability forecasts failed to predict the 2009 recession, and therefore overstated the amount of capacity required. (Pl.'s Exs. 34, 65, 116, 275, 362). Accordingly, PJM reissued forecasts with lower usage estimates which minimized PJM's reliability concerns. During the trial, there was little to no evidence that this revised usage data proved to be false.

In addition, PJM recommended the construction of the Susquehanna Connection, a new 145-mile high voltage transmission line to move electricity from Berwick, Pennsylvania to Roseland, New Jersey. Presently, officials of PJM and PSE&G anticipate that construction on the project should be completed in 2014 or 2015. This project has the potential to solve the reliability violations that PJM projected. (Def.'s Ex. 563). Despite its ongoing construction, the Board argues that the length of time needed to complete the Susquehanna Connection project has left New Jersey vulnerable to outages. As such, according to the Board, new generation within New Jersey is needed to alleviate future reliability issues.

Lastly, the retirement of coal-fired plants has been an ongoing process. Despite the Board's concerns, PJM has found that within its territory the RPM had sufficient bidders to cushion or absorb the impact of these shutdowns. In addition, through the RPM Auction, PJM has acquired more than sufficient capacity to serve its territory. As PJM reported, although changes in environmental rules have led to significant retirements, "[t]he announced generation retirements sen[t] a strong signal that there would be a need for new resources, and [the 2012] auction witnessed a record number of new generation offers." (Def.'s Ex. 204, at 2); (T. 1084, 15-22). In fact, the 2012 RPM Auction cleared enough capacity to have a 20.2% reserve margin – significantly above the 15.4% reserve margin usually reserved. It is noteworthy that one of the Board's witnesses confirmed that sufficient generation exists. Specifically, Mr. James Giuliano, Director of Reliability and Security of the Board, testified that he could not recall any power outages caused by insufficient generation. (T. 1104, 15-19).

Appointment of LCAPP Agent and MOPR Rules Revisited

In the first quarter of 2011, following enactment of the LCAPP, two significant events occurred. First, the Board appointed Levitan & Associates to be the LCAPP agent. (Pl.'s Ex. 136). Immediately after its appointment, Levitan began an exhaustive but expeditious selection process to identify generators capable of fulfilling both the requirements of the LCAPP statute and the policy objectives of the Board. Secondly, certain PJM stakeholders complained to PJM and the Commission that the state mandated exemption under MOPR should be prohibited because, under the exemption, the Board was unilaterally changing the price of capacity by imposing its own approved costs rather than relying on the competitive price of the RPM.

Levitan's evaluation of generators' proposals through the eligibility, prequalification and commercial proposal stages was based on an evaluation process "consistent with the LCAPP Law that [was] centered on the maximization of economic, environmental and community benefits from the standpoint of ratepayers in New Jersey." (Pl.'s Ex. 178, at 11). Specifically, "[a]pplicants were first reviewed in light of the requirements in the LCAPP Law to be an eligible generator. Eligible generators were then further reviewed to determine whether they should be prequalified on the basis of showing environmental, economic and community benefits, and the demonstration of meeting the proposed in-service date with reasonable certainty." (*Id.*). Furthermore, "[t]he evaluation of commercial proposals was completed in parallel with the prequalification review." (*Id.*).

According to Mr. Levitan, the "community benefits" aspect of the prequalification assessment concerned "the developer's ability to drum up support in the community to achieve the [LCAPP Act's] aggressive [construction] milestones." (T. 1313, 7-15). The benefit sought was the timely construction of a qualifying new generation facility within the PJM territory. In evaluating the economic benefit of potential projects, Levitan "look[ed] at the completeness of the technology and operating data forms . . . [to] facilitate [its] analysis in the next phase." (T. 1312, 22 through T. 1313, 3).

In total, thirty-four (34) generation projects submitted prequalification applications to Levitan. (Stipulated Facts ¶ 43). Many of these projects were disqualified for various reasons. Notably, Levitan eliminated twenty-one (21) of the projects because they "were tied to existing generation units and therefore did not meet the condition of being a new generation facility." (Stipulated Facts ¶ 45). The Board and Levitan also eliminated four (4) projects because they "were characterized as peaking units, rather than base load or mid-merit units as required by the LCAPP." (Stipulated Facts ¶ 46). After three (3) generators withdrew their applications, only six (6) generators were prequalified. (Stipulated Facts ¶ 48). Of the six generation facilities that prequalified, Levitan recommended, and the Board later approved, that three be awarded SOCAs. These generators were Hess (625.0 MW of capacity), NRG (680.1 MW of capacity), and CPV (663.4 MW of capacity). (Stipulated Facts ¶ 54). All three of these generator projects are located in New Jersey. (Stipulated Facts ¶ 52).

After the prequalification stage was completed, Levitan drafted the SOCA for each generator. The material terms of the three SOCAs are identical; they differ only with respect to the SOCA price, the quantity of capacity awarded, and the name of the generator. (T. 1368, 7-11). Herein the Court utilizes the SOCA of CPV as an example.

The Board awarded CPV a SOCA with a fifteen-year term. (Pl.'s Ex. 203). Each SOCA contains an Attachment F, which provides the schedule of Standard Offer Capacity Prices for the LCAPP generator for the fifteen-year term. CPV received the following price schedule:

Delivery Year (ending May 31st)	Standard Offer Capacity Price ($MW-day)
2016	286.03
2017	294.61
2018	303.45
2019	312.55
2020	321.93
2021	331.59
2022	341.54
2023	351.79
2024	362.34
2025	373.21
2026	384.41
2027	395.94
2028	407.82
2029	420.05
2030	432.65

Notably, CPV's SOCA has provisions which relate to PJM activity. For instance, the SOCA refers to the RPM, the RPM Auction and/or other actions that occur within PJM. (Pl.'s Ex. 203). The SOCA responsibilities which correlate to PJM activities are listed below:

> "Available Capacity Amount" means the lesser of: (i) the quantity of Unforced Capacity from the Capacity Facility that is offered by Generator and cleared by PJM in the relevant Base Residual Auction [RPM Auction], and (ii) the Awarded Capacity Amount.
>
> "Base Residual Auction" means the primary auction conducted by PJM as part of PJM's Reliability Pricing Model [RPM] to secure electrical capacity as necessary to satisfy the capacity requirements imposed under the PJM reliability assurance agreement for the Delivery Year.
>
> "Locational Deliverability Area" or "LDA" means the PJM sub-regions used to calculate Resource Clearing Prices as part of the Reliability Pricing Model.
>
> "PJM Interconnection, L.L.C." or "PJM" means the Regional Transmission Organization that manages the regional, high-voltage electricity grid serving New Jersey and all or parts of other states and, among other things, administers the Reliability Pricing Model, and any successor.
>
> "Reliability Pricing Model" or "RPM" means PJM's capacity-market model that secures capacity on behalf of electric load serving entities to satisfy load obligations not satisfied through
> the output of electric generation facilities owned by those entities or otherwise secured by those entities through bilateral contracts.
>
> "Resource Clearing Price" or "RCP" means the clearing price expressed in $/MW-day for Unforced Capacity established by the Base Residual Auction for the LDA in which the Capacity facility is located and the applicable Delivery Year as posted by PJM.
>
> "RPM Rules" means the provisions of PJM's tariffs and agreements accepted by the Federal Energy Regulatory Commission and the provisions of PJM's manuals governing the Reliability Pricing Model, as in effect from time to time during the term of this Agreement. (Pl.'s Ex. 203).

In addition to these terms, the term "delivery year" corresponds to the RPM availability requirement. Specifically, "Delivery Year" means "each 12-month period from June 1st through May 31st numbered according to the calendar year." (Pl.'s Ex. 203). The term is the same under the SOCA. The SOCA obligates the generator to qualify within the RPM by clearing the RPM Auction and acting in accordance with PJM rules. The SOCA dictates the procedure:

> 2.3.1. Generator shall use all commercially reasonable efforts to cause the Capacity Facility to qualify under the RPM Rules as a capacity resource in an amount no less than the Awarded Capacity Amount for the Base Residual Auction associated with each Delivery Year during the term of this Agreement, commencing upon the Awarded Commencement Date.
>
> 2.3.3. Throughout the Delivery Term, Generator shall:
>
> (a) Cause the Capacity Facility to comply with all obligations of a capacity resource under the RPM Rules, including without limitation the obligations relating to the submission of offers to supply electric energy and ancillary services in PJM markets, and Generator shall bear all costs associated with such compliance, including without limitation all fees and penalties imposed by PJM;
>
> (b) Submit supply offers for an amount of Unforced Capacity no less than the Awarded Capacity Amount from the Capacity Facility in accordance with the RPM Rules in the Base Residual Auction associated with each Delivery Year during the term of this Agreement, such that the Unforced Capacity shall be offered at the lowest commercially reasonable price under the RPM rules;
>
> (c) Submit supply offers from the Capacity Facility for the maximum amount of Associated Energy that the Capacity Facility can provide in the PJM day-ahead energy market in accordance with PJM Market Rules throughout the Delivery Term, such that the Associated Energy shall be offered at the lowest commercially reasonable price under PJM's Market Rules;
>
> (d) Submit supply offers from the Capacity Facility for the maximum amount of Associated Ancillary Services that the Capacity Facility can provide in the PJM ancillary services markets in accordance with PJM Market Rules throughout the Delivery Term, such that the Associated Ancillary Services shall be offered at the lowest commercially reasonable price under PJM's Market Rules;
>
> (e) Neither physically nor financially withhold any Unforced Capacity up to the amount of Awarded Capacity, or Associated Energy and Associated Ancillary Services, from the Capacity Facility;
>
> (f) Provide on a timely basis . . . (i) documentation provided to Generator by PJM after the conclusion of each Base Residual Auction

> showing the amount of Unforced Capacity offered from the Capacity Facility and cleared by PJM in such Base Residual Auction; (ii) documentation provided to Generator by PJM in advance of each Delivery Year showing all EFORd measurements for the Capacity Facility for the Delivery Year; (iii) the result of any capability test for the Capacity Facility conducted by PJM; (iv) documentation provided to Generator by PJM in advance of each Delivery Year showing the showing the Availability Capacity Amount for the Delivery Year or required to calculate the Available Capacity Amount for the Delivery Year; and (v) documentation notifying Generator of any correction to an input to a calculation." (Pl.'s Ex. 203).

The electric distribution companies have one broad obligation to the Board under the SOCA. (Pl.'s Ex. 203). That is, they must report their compliance with the abovementioned obligations to the Board. The SOCA reads, in relevant part:

> 2.4. <u>Obligations of the Utility</u>. The Utility shall prepare and file an annual report to the Board within thirty (30) calendar days after the end of each Delivery Year describing (i) the status of this Agreement, (ii) the amount of Unforced Capacity and cost of associated Transactions made under this Agreement, (iii) the performance of the Generator in supplying Unforced Capacity and Associated Energy and Associated Ancillary Services under this Agreement, and (iv) any material actions taken by the Generator or the Utility under this Agreement. Nothing in this Agreement imposes upon Utility the obligation to monitor, enforce, or declare an Event of Default with respect to the price of Unforced Capacity, or the price or amount of Associated Energy or Associated Ancillary Services, which Generator offers in or supplies to any PJM Market. (Pl.'s Ex. 203).

In addition, the SOCA sets forth a formula to make payments or receive refunds based on the SOCA amount and the clearing price at the RPM auction. The SOCA states:

> 4.1.1. If, for a Delivery Year, the SOCP is greater than the [Recourse Capacity Price] then, subject to Section 2.5, Utility will pay Generator each Month during the Delivery Year one-twelfth of the product of (i) the difference between the SOCP and the [Resource Capacity Price], (ii) the Available Capacity Amount, (iii) the number of days in the Delivery Year; and (iv) Utility Load Ratio, each for the applicable Delivery Year.
>
> 4.1.2. If, for a Delivery Year, the [Resource Capacity Price] is greater than the SOCP then, subject to Section 2.5, Generator will pay Utility each Month an amount equal to one-twelfth of the product of (i) the difference

> between the RCP and the SOCP, (ii) the Available Capacity Amount, (iii) the number of days in the Delivery Year, and (iv) Utility Load Ratio, each for the applicable Delivery Year.
>
> 4.2. Structure of Transaction. Nothing in this Agreement shall entitle or obligate Utility to purchase, or take title to or delivery of, capacity, electric energy, or ancillary services from the Capacity Facility.

Under the SOCAs, "the LCAPP generators receive the payment set forth in the SOCAs only if they successfully sell the capacity from their facilities in the RPM base residual auction." (Stipulated Facts ¶ 56). The SOCAs also require the winning bidder to use all commercially reasonable efforts to construct an electric generation facility prior to the "commencement date" of its RPM obligation. (Stipulated Facts ¶ 58).

Finally, the SOCA requires that eligible generators maintain all approvals they have with PJM, and to "comply with Commission and RPM rules." The agreement sets forth:

> 6.2. Maintain Authorizations. Each party will use all reasonable efforts, including the maintenance of records and provision of notices, to maintain in full force and effect all consents, licenses or approvals of PJM and of any Governmental Authority or other authority that are required to be obtained by it with respect to this Agreement, the Construction Period Security, and the Delivery Term Security and its obligations hereunder and thereunder and will use all reasonable efforts to obtain any that may become necessary in the future.
>
> 6.3. Comply with Laws and RPM Rules. Each party will comply in all material respects with all Applicable Laws and orders and all RPM Rules to which it may be subject if failure so to comply would materially impair its ability to perform its obligations hereunder or under the Construction Period Security or Delivery Term Security.

In accordance with the terms of its SOCA, CPV (as well as the other two eligible generators) sought admission into the RPM Auction. According to Mr. Knight, as part of CPV's admissions process, representatives of CPV met with PJM to discuss the impacts of the MOPR II revisions and what information CPV would be required to submit. In response to a request for information issued by PJM, CPV sent an application consisting of more than 600 pages of materials. Within its application, CPV claimed it was exempt under the unit-specific exemption of MOPR II adopted in 2011, not the state mandated exemption provided for in the original MOPR. Under MOPR II, CPV could bid into the RPM auction at less than the minimum offer price floor (90 percent of net cone) if it could demonstrate that its actual costs were less than the benchmark price. (T. 1661:21 through T. 1673, 23); (Def.'s Ex. 51).

In determining whether CPV qualified for a unit-specific exemption pursuant to MOPR II, PJM did not consider any out-of-market payments that CPV would receive through New Jersey's LCAPP program. (Def.'s Ex. 183, 751); (T. 1674, 14 through T. 1675). Pursuant to its practice under the MOPR screen, PJM advised CPV that it would accept a bid of no less than \$151.24 / MW-day, which is the level at which CPV bid. (T. 1678, 18-20). The May 2012 RPM Auction cleared at \$167.46 / MW-day. (Def.'s Ex. 204); (Stipulated Facts ¶ 59). According to Mr. Knight, the RPM Auction price was different than the Board's approved costs due to "a difference in timing, and then secondarily a difference in the view on energy." (T. 1677, 12). With regard to the other eligible generator projects, Hess Corp's project cleared the auction while NRG's proposed project did not. Adamantly opposed, the four electric distribution companies signed the SOCAs under protest.

H. IMPACT OF THE LCAPP STATUTE ON GENERATORS

Plaintiffs' witnesses testified that their respective companies rely on the forward price signals of the RPM Auction in deciding whether to develop new generation resources or make investments in existing resources within a specific market. According to these witnesses, the LCAPP makes it more difficult for these companies to make such business decisions because they can no longer rely on the RPM Auction price signals to evaluate their future costs and predict future revenue streams. In the view of the plaintiffs, the RPM Auction clearing price

($167.46) was essentially displaced and supplanted by the SOCA price written into the SOCA contracts ($286.03), causing less predictability in the energy capacity markets.

Zamir Rauf, Plaintiff Calpine's Chief Financial Officer, testified that the RPM Auction price signals play a "huge role" in Calpine's assessment as to whether an investment should be made because those prices are the basis for "projections as to where [Calpine] think[s] the market is going to be." (T. 1112, 3-14); (Def.'s Ex. 289, at 1). He expressed Calpine's reluctance to proceed with expansion plans in light of the LCAPP's enactment. In fact, according to Mr. Rauf, the LCAPP was a "very strong factor" in Calpine's decision to construct only half of its Garrison project as opposed to completing the project as originally planned. (T. 1121, 15 through T. 1130, 15). Mr. Rauf noted that Calpine was initially attracted to invest in the PJM region because it was a competitive market "where you can put your capital at risk, and compete based on your efficiency[.]" (T. 1114, 15-18 through T. 1115, 6-21). While Calpine "would love to invest more money into PJM[,]" as a result of the LCAPP, the company is now "taking a step back and just holding up from putting too much money into PJM . . . pending this uncertainty." (T. 1134, 8-12). Mr. Rauf summarized the conundrum for energy developers after the LCAPP's enactment:

> [T]he PJM market was designed with certain rules, and everyone has to play by the same rules. . . . [H]ow do you know the state two months from now or six months from now, a year from now, two years from now suddenly decides we need to create jobs let's build another power plant, or whatever political reason they may have for doing so. And all of a sudden they decide to build another plant, whereas you may have been in -- in the process of building one anyway or you may have started building one and now your capital's at risk because the price signals that were in the marketplace are no longer there because of this new plant, so it really just disrupts the whole marketplace, it just in my mind creates enough chaos to where you've got to be very cautious about putting money in a market where you don't know what the rules are, especially when the rules are being manipulated by the politicians. (T. 1130, 20 through T. 1131, 14).

As Mr. Rauf plainly stated, in light of the LCAPP, Calpine would "put[] less money in PJM than [the company] otherwise would have, and [Calpine] would probably either be reinvesting that money in other regions, or buying back [its] stock." (T. 1132, 6-12).

PSEG Power also had similar concerns regarding the impact of the LCAPP. According to Daniel Cregg, the LCAPP Act "dramatically change[d] how we look at what the market is." (T. 888, 20 through T. 889, 8). He noted that PSEG Power "shifted entirely away from . . . looking at it as a merchant opportunity" and began rationalizing that the "opportunity [was] not going to be there for [them] this year". (T. 879, 2-7). In the May 2012 RPM Auction, PSEG Power bid its Essex County project "at a fairly high level" in order to serve "as a backstop to the extent that the LCAPP units [did not] bid." (T. 886, 22 through 888, 12). In other words, "absent the LCAPP Act . . . there might have been a price signal that would have been there" for the Essex County project, but instead, "the LCAPP units did bid in, and as a result [PSEG Power's Essex] unit did not clear." (T. 887, 4-8).

The LCAPP also had an impact on the operations of Exelon, as discussed by Mr. Dominguez during his testimony. Specifically, he testified that the RPM price signal "tells [Exelon] whether to make investments in existing plants; whether to increase the capacity of existing plants; whether to do environmental retrofits; [and] whether to keep plants open." (T. 527, 2-10). Mr. Dominguez further testified that, given its impact on Exelon's business strategies, the RPM is "fundamental to the way [Exelon] operate[s] [its] business." (T. 527, 8-10). In addition, Mr. Dominguez stated that the LCAPP Act has "fundamentally chang[ed] [Exelon's] ability to predict revenue streams for existing megawatts." (T. 564, 3-16). The LCAPP has also been a factor in Exelon's decision to place its nuclear uprate program on hold. (T. 564, 16).

PPL has also had to modify its business strategies in light of the requirements imposed by the LCAPP. Michael Cudwadie, Vice President for PPL EnergyPlus, testified that PPL relies on capacity forward market prices and energy forward market prices to make decisions regarding investments in new and existing generation, including whether to upgrade units, add pollution control equipment, or retire specific units. (T. 1041, 18-24).

The effects of the LCAPP described by these witnesses were echoed at trial by Plaintiffs' experts Mr. Massey and Professor Willig. For example, Mr. Massey declared that "[t]he entire fabric of the contract in my judgment makes it a price for capacity. It so happens that the contract calls it a standard offer capacity price, I . . . can hypothesize about a lot of things, but I don't know what can be clearer than that." (T. 296, 19-23). Mr. Massey elaborated by stating that "[t]he price is measured in terms of the netting of revenues, is measured in terms of comparing the standard offer capacity price, with the price determined in the PJM capacity market. It's all about capacity pricing." (T. 298:2-10). Furthermore, the payments under the SOCA are "inextricably linked to the sale of wholesale capacity." (T. 298, 2-10).

Similarly, Professor Willig described the effect of the LCAPP as "wiping out the pricing mechanism of PJM . . . [and] taking it away and putting this alterative, the SOCA price, in the place of the market price." (T. 638, 22 through T. 639, 1). Professor Willig opined that the "architecture" of the RPM Auction was appropriately designed to address concerns in the energy capacity market (T. 763, 19-23) and that the RPM clearing price "is being displaced, . . . overridden, [or] supplanted, by the SOCA price through this mechanism which is written into the SOCA contract and governed by the LCAPP." (T. 637, 15-18).

Professor Willig further stated that the LCAPP would actually undermine new generation projects because all future investors would insist on receiving similar government assistance. He explained:

> Even though this is supposed to be an interstate market, the kinds of freedoms for the states, which they may have political incentives to act on, favoring their own development projects, will lead in a contagious way to other states taking measures that they think are only there in self-protection but are really their own reaction to the beginnings of this movement if the Court allows it, so that it's truly a contagion. We could very well be seeing a rash of programs of this kind, only furthering the rational insecurity of new investors who are not going to be part of these programs, fearing that the market will just be full of unfair competition for them, and thereby discourage their own investment activities. (T. 698, 11-23).

Defendants' Perspective

The defendants have a completely different view concerning the impact and effects of the LCAPP based on two factual disagreements with the plaintiffs. First, the defendants contend that the RPM and the SOCA are two separate and unrelated transactions. The fact that each provides a different price does not, according to the defendants, frustrate the purpose or goals of the RPM Auction because, in their view, the SOCA is a purely financial contract not subject to Commission oversight and authority. Second, the defendants argue that any jurisdictional conflicts between the Board and the Commission were resolved by the Commission's 2013 MOPR revisions. Both of these arguments are addressed below.

According to the defendants, the RPM and the SOCA are unrelated. As Mr. Knight of CPV testified, the SOCA is "something separate and distinct." (T. 1646, 6-13). In describing this distinction, Mr. Knight elaborated that the "SOCA is between CPV and the EDCs, and does not go through PJM or have to do with PJM." (T. 1646, 6-13). He further pointed out that "[CPV] sell[s] physical capacity and energy to PJM," and does "not sell any physical capacity to anybody else.” (T. 1644, 12-22). Mr. Knight distinguished the SOCA price from the RPM Auction clearing price by stating:

> The SOCA -- I mean the general terms of the SOCA are relatively simple and straightforward, but the obligation is for us to build a power plant, and to bid into, connect into PJM, and sell all our energy and capacity into PJM. And then in return for that we receive a financial payment from the EDCs, that is based upon a formula we're all . . . familiar with. It's a fixed price for a floating price, the floating price being the index in the PJM capacity market. (T. 1644, 12-22).

Defendants further contend that because the SOCA is a purely financial contract, it is not subject to Commission oversight. (T. 1911, 13-16). In fact, Defendants liken the SOCA to other financial contracts such as swaps, collars, or contracts for differences. (T. 682,2 through T. 683, 7). While the latter term (contract for differences) was mentioned frequently throughout trial, it was not fully defined except as an instrument that is routinely used to manage commodity price risks. (T. 1347, 1-15). For example, Mr. Levitan explained that a contract for differences is a “financially settled mechanism that provides revenue assurance for the seller and risk management benefits for the buyer.” (T. 1282: 10-18). In the view of the defendants, because the SOCAs do not involve the sale of actual physical energy capacity, they fall outside the jurisdictional authority of the Commission. (T. 1282, 10-18). Mr. Knight agreed with this analysis and likened the SOCAs to insurance policies indemnifying against forced power outages. He testified:

> Because the payment mechanism is contingent upon something, it doesn't mean that we're delivering capacity . . . . [A]n example would be we have forced outage insurance in which we get paid by someone under a derivative contract if we are forced out. That doesn't mean that that's forced outages . . . it's just a contingency within the contract by which you get paid, it's not [like] you're actually delivering some good. T. 1648, 20 through T. 1649, 3).

So, under the defendants' analysis, the SOCAs are ultimately just financial risk management tools through which no capacity or energy is bought or sold. (T. 1283, 17-24); (T. 1360, 9 through T. 1369, 10); (T. 1644, 9 through T. 1645, 9).

With the adoption of the MOPR III revisions, the defendants argue that issues between the Board and the Commission concerning participation of new generators in the RPM Auction are resolved; and since there is no controversy between the Board and the Commission, there is no need for the Court to impose any remedy. The Court, however, rejects this argument for several reasons. Although the Board and the Commission may now have a more cooperative relationship, the Court is in the best position to determine whether the LCAPP and the related policies implemented by the Board violate the Supremacy Clause. In addition, despite the increased cooperation between the Board and the Commission, this remains a controversy between the plaintiffs (generators and distributors of electricity) and the Board.

Other Alternatives

Since the Board retained authority over the siting of generation facilities, a question arose as to whether the Board had any alternative means to incentivize construction of new generation facilities besides enacting a statute like the LCAPP. The parties agree that the Board had a number of ways to support and encourage the development of generation projects. These include the utilization of tax exempt bonding authority, the granting of property tax relief, the ability to enter into favorable site lease agreements on public lands, the gifting of environmentally damaged properties for brownfield development, and the relaxing or acceleration of permit approvals. (T. 266, 25-26 through T. 267, 6); (T. 1313-14 through T. 1316, 2).

I. CREDIBILITY OF WITNESSES AND WEIGHING OF THE EVIDENCE

As opposed to the facts set forth above, to which the Court has given considerable weight, the trial record reveals an extensive number of other facts which were given little weight in this decision. Those facts, and the reasons they were given little weight, are discussed below.

First, Defendants presented a plethora of facts about initiatives in Maryland and Connecticut which they believe present issues similar to those being considered in this case. The Maryland initiative is subject to a separate ongoing lawsuit. As Mr. Roach testified, it is based upon reimbursement of 400 megawatts of new demand response as opposed to a capacity requirement. (T. 2066, 20-24). Any analysis of the Maryland proposal would necessarily require this Court to review a set of facts as substantial as those presented herein. Based on the facts presented at trial, the Court is not able to discern whether Maryland's proposal is sufficiently similar to the LCAPP. As such, the Court considers the value in comparing and contrasting the Maryland initiative and the LCAPP to be minimal for purposes of this opinion.

In regards to the Connecticut proposal, the defendants contend that a Connecticut peaking facility has a very similar financial structure as a New Jersey peaking facility under the LCAPP. (T. 1377, 24 through T. 1379, 11). Evidently, PSEG Power or one of its subsidiaries previously accounted for SOCA-like payments to a New Haven generator as financial contracts. According to the defendants, the payments in question were not listed as energy or capacity contracts required to be filed with the Commission. (Def.'s Ex. 630). The defendants argue that this supports their proposition that SOCAs are purely financial instruments. The Court, however, did not have sufficient information to fully analyze the Connecticut payments and, therefore, gave the defendants argument little weight. In the Court's view, the most compelling evidence regarding how the SOCAs should be defined under the law was adduced by the witnesses at trial.

Therefore, in terms of credibility, the evidence regarding the Connecticut contracts was of little value.[9]

The Plaintiffs argue that certain written and oral statements allegedly made by Board staff and CPV executives are admissions against interest supporting the plaintiffs' case. Examples of these alleged admissions include:

a. Comments to President Solomon made by Frank Perrotti, Assistant Director of the Board, in which he stated that the LCAPP has the "potential to drive out other forms of investment or, at least, cause future developers to demand the same premiums before deploying capital." (Pl.'s Exs. 70, 406).

b. Comments made by President Solomon's aide Kristi Miller in which she stated that the LCAPP "could encourage future developers to demand identical premiums before deploying capital." (Pl.'s Ex. 406, at 20).

c. Comments made by CPV Chief Executive Officer Douglas Egan in which he indicated that in order to develop generation in New Jersey, a generator may need "out-of-market pricing" (Pl.'s Ex. 61) or "pricing that was higher than what was available at that point in time." (Pl.'s Ex. 409).

d. Comments made by the Board's Fed. R. Civ. P. 30(b)(6) designated witness, Mr. Dembia, in which he indicated that the LCAPP is a "guaranteed payout." (Pl.'s Ex. 406).

The Court gave little weight to these alleged admissions which occurred during the lobbying effort to enact the LCAPP. *See Kentucky W. Va. Gas Co. v. Pennsylvania Pub. Util. Comm'n*, 837 F.2d 600, 615 (3d Cir. 1988). The Court found that the witnesses at trial presented

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[9] On a motion *in limine* prior to trial, the Court ruled that the Connecticut initiative was not relevant because it involved a different state. During trial, the Court reopened that decision since the plaintiff's presented evidence involving initiatives in other states. The Court determined fairness required an evaluation of the Connecticut evidence.

the facts and issues in a forthright manner. Since the statements were not subject to cross-examination, and could not be assessed for credibility, the Court believes the constitutionality of the New Jersey statute and program is best determined by reviewing the merits of the case rather than relying on isolated statements.

Plaintiffs also introduced a report prepared by the Brattle Group for purposes of showing the successes of the RPM. The Brattle Group is a consulting firm hired by PJM to evaluate the RPM. (Pl.'s Ex. 49). No one from the Brattle Group testified at trial. As a result, the Brattle Group's report on the RPM Auction was not subject to cross-examination. As such, the Court gave the report little weight.

J. ANALYSIS

"Preemption is a doctrine of American constitutional law under which state and local governments are deprived of their power to act in a given area, whether or not the state or local law, rule or action is in direct conflict with federal law . . . . The analysis of a preemption dispute focuses upon statutory construction . . . in the context of a constitutional framework of sovereignty, commerce regulation, or other predicate for federal powers."[10] More specifically, preemption doctrine is rooted in the Supremacy Clause of the United States Constitution. Article VI declares that the laws of the United States "shall be the supreme Law of the Land; . . . any Thing in the Constitution or Laws of any State to the Contrary notwithstanding." U.S. Const. art. VI, cl. 2. In order to determine whether the LCAPP is preempted under federal law, the first factual issue to resolve is whether the Board-ordered SOCAs occupy the same field of regulation as the Commission and intrude upon the Commission's authority to set prices for wholesale energy sales.

[10] JAMES T. O'REILLY, FEDERAL PREEMPTION OF STATE AND LOCAL LAW: LEGISLATION, REGULATION AND LITIGATION 1 (2006).

According to the defendants, the Commission's oversight authority is "limited to sales of the actual physical electricity (or capacity) to a buyer." (Def.'s Post-Trial Br. at 11). Furthermore, the defendants contend that "[c]ontracts that do not effect a physical sale of electricity . . . are not subject to [Commission] jurisdiction." (*Id*.). In the defendants' view, the SOCAs are purely financial contracts that do not involve physical sales of electricity.[11] As such, according to the defendants, the SOCAs are separate and unrelated to the RPM Auction process and free from Commission oversight. Plaintiffs argue, in opposition, that the "State, through the LCAPP Act and Board-ordered SOCAs, has set a price to be received for the wholesale sale of capacity to PJM." (Pl.'s Post-Trial Br. at 3). In the plaintiffs' view, the LCAPP ultimately "award[s] an impermissible price supplement for an interstate wholesale sale of electricity" and replaces the RPM price with the Board-ordered SOCA price. (*Id*. at 1). In doing so, according to the plaintiffs, the Board essentially sets a price for wholesale energy sales and, therefore, "regulat[es] in a field that is reserved exclusively" for the Commission. (*Id*.).

The Court finds that the SOCAs occupy the same field of regulation as the Commission and intrude upon the Commission's authority to set wholesale energy prices through its preferred RPM Auction process. As previously discussed, many of the terms defined in the SOCAs make substantial use of RPM terminology. In addition, the SOCAs obligate eligible generators to:

(1) "qualify under the RPM rules as a capacity resource in an amount no less that the Awarded Capacity Amount for the [RPM Auction]" (Pl.'s Ex. 203, at 9);

(2) "comply with all obligations of a capacity resource under the RPM Rules" (*Id*.);

(3) "[s]ubmit supply offers . . . in accordance with the RPM Rules" (*Id*.); and

[11] The Commission has previously held that "electricity price risk management transactions (futures, options, swaps, and the like)" that do not result in the actual delivery of electricity are "purely financial" and need not be reported to the Commission." *Morgan Stanley Capital Group, Inc.*, 69 F.E.R.C. ¶ 61,175, 61,696 (1995).

(4) "[s]ubmit supply offers . . . in accordance with PJM Market Rules[.]" (*Id*. at 9-10). The LCAPP Act itself defines the SOCA as a "capacity price . . . to be received by eligible generators under a Board-approved SOCA." (Pl.'s Ex. 127, at 10). Furthermore, payment of the SOCA price is made only if the LCAPP generators successfully sell and deliver wholesale capacity to PJM. Given the fact that the SOCAs require eligible generators' to satisfy certain RPM rules and mandate that the generators undertake certain performance under those rules, the Court finds that the performance of the SOCAs is contingent upon clearing the RPM Auction. As such, the SOCAs are not separate from, and to the contrary, occupy the same field as the RPM Auction.

"Under the Supremacy Clause, federal law may supersede state law in several different ways." *Hillsborough County v. Automated Med. Labs., Inc*., 471 U.S. 707, 713 (1985). Specifically, the Supreme Court has recognized three types of preemption: express preemption, implied conflict preemption, and field preemption. *Id*. In this case, Plaintiffs argue that the Federal Power Act supersedes the LCAPP under both the field and conflict preemption theories.

Courts must begin their analysis of preemption questions by applying a presumption against preemption. *Cipollone v. Liggett Group, Inc.*, 505 U.S. 504, 516 (1992). "In areas of traditional state regulation, we assume that a federal statute has not supplanted state law unless Congress has made such an intention 'clear and manifest.'" *Bates v. Dow AgroSciences* 544 U.S. 341, 449 (2005) (citing *New York State Conference of Blue Cross & Blue Shield Plans v. Travelers Ins. Co.*, 514 U.S. 645, 655 (1995). "That assumption applies with particular force when Congress has legislated in a field traditionally occupied by the States." *Altria Grp., Inc. v. Good*, 555 U.S. 70, 77 (2008). Thus, when the "text of a pre-emption clause is susceptible of more than one plausible reading, courts ordinarily 'accept the reading that disfavors preemption.'" *Id.* (citing *Bates*, 544 U.S. at 449). *See also Cipollone*, 505 U.S. at 518. Nonetheless, in the face of clear evidence, the presumption against preemption can be overcome. *See Crosby v. Nat'l Foreign Trade Council*, 530 U.S. 363, 374 n.8 (citing *Hines v. Davidowitz*, 312 U.S. 52, 67 (1941). ("Assuming, *arguendo*, that some presumption against preemption is appropriate, we conclude . . . that the state Act presents a sufficient obstacle to the full accomplishment of Congress's objectives under the federal Act to find it preempted."). While applying the presumption against the preemption, the Court reviews whether the Federal Power Act preempts the LCAPP under either the field preemption or conflict preemption theories.

Field Preemption

Field preemption arises by implication when state law occupies a "field reserved for federal regulation." *United States v. Locke*, 529 U.S. 89, 111 (2000). The Supreme Court has explained that "[f]ield preemption reflects a congressional decision to foreclose any state regulation in the area, even if it is parallel to federal standards." *Arizona v. United States*, 132 S. Ct. 2492, 2502 (2012). This occurs when "Congress has left no room for state regulation of these matters." *Locke*, 529 U.S. at 111 (citing *Fidelity Fed. Savings & Loan Ass'n v. De La Cuesta*, 458 U.S. 141 (1982). The Supreme Court has explained that a congressional intent to occupy a field can be inferred when "[t]he scheme of federal regulation may be so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it." *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947). It may also be inferred where "an Act of Congress 'touches a field in which [the] federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject.'" *English v. General Elec. Co.*, 496 U.S. 72, 79 (quoting *Rice*, 331 U.S. at 230). Nonetheless, because field preemption typically arises in areas traditionally regulated by states under their police powers, "congressional intent to supersede state laws must be 'clear and manifest.'" *English*, 496 U.S. at 79 (quoting *Jones v. Rath Packing Co.*, 430 U.S. 519, 525 (1977). Generally, "[t]he factors used to determine if the field has been fully occupied by federal power include the dominant federal interest, the expression of congressional purpose, and the pervasiveness of the federal regulatory system." O'Reilly, *supra* note 10, at 70.

Since the Supreme Court's 1927 decision in *Public Utils. Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927), there has been a dominant federal interest over wholesale sales of electricity in interstate commerce. In that case, the Supreme Court invalidated an attempt by Rhode Island to regulate the rates charged by a Rhode Island plant selling electricity to a Massachusetts company, which resold the electricity to the City of Attleboro, Massachusetts. The Court found that the State's attempt to regulate rates "place[d] a direct burden upon interstate commerce" and, as a result, the "State [was] restrained by the force of the Commerce Clause." *Id.* at 89. Ever since the Court's ruling, the federal government has asserted jurisdiction over wholesale sales of electricity in interstate commerce. As noted in Section E of this memorandum, in the absence of any federal regulatory body, interstate wholesale electricity pricing was left entirely unregulated after the *Attleboro* decision. In order to fill that regulatory gap, Congress enacted the Federal Power Act which provided that the Commission shall have jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1). *See New York v. FERC*, 535 U.S. 1, 20-21 (2002) ("It is clear that the enactment of the FPA in 1935 closed the '*Attleboro gap*' by authorizing federal regulation of interstate, wholesale sales of electricity – the precise subject matter beyond the jurisdiction of the States in *Attleboro*. . . . It is, however, perfectly clear that the original FPA did a good deal more than close the gap in state power identified in *Attleboro*. The FPA authorized federal regulation not only of wholesale sales that had been beyond the reach of state power, but also the regulation of wholesale sales that had been *previously subject* to state regulation.").

Plaintiffs contend that in enacting the Federal Power Act, Congress "chose to occupy the field of wholesale electricity sales, including the price at which electricity is sold at wholesale, and the terms and conditions under which such electricity is sold." (Pl.'s Post-Trial Br. at 12). Such a contention is supported by previous decisions in which courts have held that the Commission has the exclusive authority to regulate wholesale electricity sales and the transmission of energy in interstate commerce. As stated by Justice Scalia, "It is common ground that if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject." *Miss. Power & Light Co. v. Miss. Ex rel. Moore*, 487 U.S. 354, 377 (1988) (Scalia, J., concurring in the judgment). The Supreme Court has held that the Federal Power Act "left no power in the states to regulate licensees' sales for resale in interstate commerce." *FPC v. S. Cal. Edison Co.*, 376 U.S. 205, 215 (1964). Moreover, the Court has repeatedly held that the federal statute "delegated to . . . the Federal Energy Regulatory Commission, exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce, without regard to the source of production." *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982) (citing *United States v. Pub. Utils. Comm'n of Ca.*, 345 U.S. 295, 311 (1953). *See also Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 956 (1986) (stating that the Commission "has exclusive jurisdiction over interstate wholesale power rates."). The Third Circuit has similarly found that the "wholesale market for electrical energy is regulated by [the Commission]" and "[o]ne of [the Commission's] duties is to set 'just and reasonable' wholesale electric rates." *Utilimax.com v. PPL Energy Plus LLC*, 338 F.3d 303, 305 (3d Cir. 2004). The

Commission's decision to exercise its exclusive authority to regulate wholesale electricity sales through the RPM Auction process indicates both a dominant federal interest in the RPM and a pervasive federal regulatory structure to ensure its proper implementation.

To support their proposition that the SOCAs are not "[c]ontracts . . . effect[ing] a physical sale of electricity" and, therefore, "not subject to [Commission] jurisdiction[,]" the defendants rely on the case of *New York Mercantile Exch.*, 74 F.E.R.C. ¶ 61, 311, 1996 F.E.R.C. LEXIS 454 (1996) ("*NYMEX*"); (Def.'s Post-Trial Br. at 12). In *NYMEX*, the Commission held that the Federal Power Act and its reporting requirements did not apply to an electricity futures contract that was approved for trading by the Commodity Futures Trading Commission ("CFTC") except if the "contract goes to delivery, the electric energy sold under the contract will be resold in interstate commerce, and the seller is a public utility." *NYMEX*, 74 F.E.R.C. at 61,984. Without reviewing all of the facts of *NYMEX*, the Court finds the case distinguishable for several reasons. First, no evidence was presented to indicate that the SOCAs have been approved for trading by a separate federal regulator. Second, there is a caveat in *NYMEX* that if a contract "goes to delivery" it may give rise to Commission jurisdiction. Here, the SOCA agreements are contingent upon the LCAPP generators' successful sale of capacity to PJM. Such capacity sales may constitute delivery within the meaning of *NYMEX* and, therefore, give rise to Commission jurisdiction.

The most credible testimony presented at trial confirming that the SOCA contracts are not purely financial contracts, and that they, therefore, intrude upon the exclusive jurisdiction of the Commission, was that of Professor Willig. He explained that, in economics, a purely financial arrangement is one that does not "involve any real performance." (T. 681, 5-6). He elaborated that "[a] financial deal does not involve any performance of a real side activity as part of the deal. So that's really the dividing line, and I think it's quite clear, it goes back to what we mean by price in economics, payment for performance." (T. 681, 21-24). Here, the SOCAs expressly condition payment on physical performance. As Professor Willig explained, under the SOCAs, the LCAPP generator has "got to build a plant, it's got to provide capacity, the capacity has to be available, had to be bid into RPM and into the auction, it has to clear the auction; there are all these elements of performance to which the SOCA payments are conditioned. So it's payment for performance." (T. 684, 10-15). Here, the LCAPP supplants the federal statute, and intrudes upon the exclusive jurisdiction of the Commission, by establishing the price that LCAPP generators will receive for their sales of capacity. The Court finds that in doing so, the LCAPP "places a direct burden upon interstate commerce" within the meaning of the *Attleboro* decision. Accordingly, the LCAPP Act invades the field occupied by Congress and is preempted by the Federal Power Act.

Defendants argue against preemption by stating that "Congress expressly reserved to the States exclusive jurisdiction to regulate generation." (Def.'s Post-Trial Br. at 23). According to the defendants, "State regulation of generation will not be pre-empted if the regulation's impacts on wholesale rates are merely 'incident of efforts to achieve a proper state purpose.'" (*Id*. (quoting *Nw. Central Pipeline Corp. v. State Corp. Comm'n of Kansas*, 489 U.S. 493, 515-16 (1989). Although the State of New Jersey and the Board retained the responsibility for the siting and construction of power plants, they are required to exercise this responsibility without interfering with the Commission's exclusive authority to regulate wholesale sales of electricity in interstate commerce. As discussed in Section H of this memorandum, there were other alternative measures which New Jersey could have employed to incentivize the development of new generation. While New Jersey retained the authority to take a wide range of actions to ensure reliable electric service for its citizens and encourage the construction of new electric generation facilities, it chose to advance those goals through a mechanism that intrudes upon the authority of the Commission and violates federal law.

The defendants also contend that preemption analysis "does not justify a 'freewheeling judicial inquiry into whether a state statute is in tension with federal objectives." (Def.'s Post-Trial Br. at 23) (quoting *Chamber of Commerce of U.S. v. Whiting*, 131 S. Ct. 1968, 1985 (2011). Here, however, the Commission's exclusive authority over wholesale energy sales has existed since *Attleboro* and been confirmed by the Supreme Court and many lower courts decisions. An application of these prior decisions acknowledging the exclusive authority of the Commission to regulate wholesale electricity sales to the facts in this case certainly does not constitute "freewheeling."

<u>Conflict Preemption</u>

Conflict preemption occurs where there is a conflict between a state law and a federal law. *See Crosby*, 530 U.S. at 372 ("[E]ven if Congress has not occupied the field, state law is naturally preempted to the extent of any conflict with a federal statute."). Such a conflict occurs when "the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." 132 S. Ct. at 2501. When confronting arguments that a law stands as an obstacle to Congressional objectives, a court must use its judgment: "What is a sufficient obstacle is a matter of judgment, to be informed by examining the federal statute as a whole and identifying its purpose and intended effects." Crosby, 530 U.S. at 373. The court must look to "'the entire scheme of the statute'" and determine "'[i]f the purpose of the [federal] act cannot otherwise be accomplished--if its operation with its chosen field [would] be frustrated and its provisions be refused their natural effect.'" *Id*. (quoting *Savage v. Jones*, 225 U.S. 501, 533 (1912)).

Where a state law conflicts with a federal law, the Court does not balance the competing federal and state interests. In fact, the Supreme Court has held that "[u]nder the Supremacy Clause of the Federal Constitution, '[t]he relative importance to the State of its own law is not material when there is a conflict with a valid federal law,' for 'any state law, however clearly within a State's acknowledged power, which interferes with or is contrary to federal law, must yield.'" *Felder v. Casey*, 487 U.S. 131, 138 (1988) (quoting *Free v. Bland*, 369 U.S. 663, 666 (1962)); *see also Gade v.Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88, 108 (1992) ("[E]ven state regulation designed to protect vital state interests must give way to paramount federal legislation." (quoting *De Canas v. Bica*, 424 U.S. 351, 357 (1976)).

From reviewing the entire scheme of the RPM process, it is clear that the LCAPP Act poses as an obstacle to the Commission's implementation of the RPM. The testimonies of Messrs. Dominguez, Rauf and Cudwadie indicated that their companies rely on the competitive price signals of the RPM Auction to determine future company business plans. Each testified that the SOCA prices undermine their respective company's ability to use those RPM price signals to make sound business decisions. Each also contended that the future expansion of their respective companies would be contingent on whether the SOCA price continues to supplant the RPM Auction price. The effects described by the witnesses demonstrate that the SOCA's imposition of a government imposed price creates an obstacle to the Commission's preferred method for the wholesale sale of electricity in interstate commerce.

Commerce Clause

The Plaintiffs argue that the LCAPP Act also must be invalidated under the Commerce Clause. This argument concerns the procurement of the capacity wherein Plaintiffs argue that Board discriminated against out-of-state generators in its solicitation of bids to become eligible generators under the LCAPP. The "dormant" aspect of the Commerce Clause prohibits states from using their regulatory power to discriminate in favor of in-state producers at the expense of those out-of-state. *C&A Carbone, Inc. v. Town of Clarkstown*, 511 U.S. 383, 389-90 (1994); *W. Lynn Creamery, Inc. v. Healy*, 512 U.S. 186, 192 (1994); *Wyoming v. Oklahoma*, 502 U.S. 437, 454-55 (1992). The Supreme Court has defined forbidden discrimination as "differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter." *United Haulers Ass 'n v. Oneida-Herkimer Solid Waste Mgmt. Auth.*, 550 U.S. 330, 338 (2007) (quotation marks omitted): *W. Lynn Creamery*, 512 U.S. at 192.

When a law discriminates against out-of-state producers on its face, the State bears the burden of demonstrating, "under rigorous scrutiny, that it has no other means to advance a legitimate local interest." *C&A Carbone*, 511 U.S. at 392. "Statutes that discriminate by 'practical effect and design,' rather than explicitly on the face of the regulation, are similarly subjected to heightened scrutiny." *Tri-M Group, LLC v. Sharp*, 638 F.3d 406, 427 n.28 (3d Cir. 2011).

The plaintiffs argue that the "community benefit" points awarded to generators in New Jersey effectively prohibited out-of-state generators from competing to be eligible generators under the LCAPP Act. According to the plaintiff's, the LCAPP Act – through its express consideration of economic and community benefits – favored in-state enterprises over out-of-state enterprises." (Pl.'s Post-Trial Br. at 48). To demonstrate this, the plaintiffs rely on the following evidence: (1) President Solomon's letter to Governor Christie that mentions a preference for in-state generators (Pl.'s Ex. 84); (2) the initial draft of the LCAPP legislation that promoted construction of qualified in-state electric generators (even though such language was deleted prior to enactment) (Pl.'s Ex. 94); (3) language in the LCAPP which required the Board to consider the "economic[] and community benefits" of a project (Pl.'s Ex. 127); and (4) language in the 2011 New Jersey Energy Master Plan which discussed fostering the commercialization of new generation plants in New Jersey. (Pl.'s Ex. 270).

Despite the abovementioned evidence, the plaintiffs fail to overcome the most persuasive evidence that substantiates the reasons the State is seeking in-state development. A significant portion of the trial focused on locational deliverability areas (LDAs). (Stipulated Fact ¶ 30). As previously noted, New Jersey is located in such an area that is known as EMAAC. In addition, there are two other locational deliverability areas within New Jersey known as PSEG and PS North (T. 1529, 3-13). Generally, these LDAs have higher capacity prices than other PJM areas due to transmission costs. Even the Plaintiffs agree that a capacity price cannot be set for an entire region. (Pl.'s Ex. 26, at 34). As a result, there is separation in price which is authorized by PJM and the Commission. The record as a whole supports the proposition that the closer the generation facility is to the delivery area, transmission costs will subside. As Mr. Herling concluded when discussing the reliability crisis, reliability issues could only be resolved in one of two ways – transmission via the Susquehanna Connection or additional *generation in or near the location where the reliability issue will occur.* (Def.'s Ex. 563, at 33) (emphasis added). As such, it appears reasonable that the Board would incentivize construction in areas where reliability concerns are in flux. As such, the Board has the authority to incentivize construction within New Jersey. What is good for the goose is good for the gander. As such, the incentive for community benefits to generators in New Jersey appears reasonable. Since Plaintiffs have not briefed or argued the commerce clause in such a fashion, the Court finds that Plaintiff has not met its burden of proof.

K. CONCLUSION

Based on the foregoing facts and law, the Court declares that the Long Term Capacity Agreement Pilot Program Act (LCAPP) is preempted by the Federal Power Act and in violation of the Supremacy Clause of the United States Constitution; and is therefore null and void.

s/Peter G. Sheridan
PETER G. SHERIDAN, U.S.D.J.

October 11, 2013

GLOSSARY OF ACRONYMS

BGS	Basic Generation Service
BPU OR NJBPU	The Board of Public Utilities of the State of New Jersey; also referred to as "the Board"
BRA	Base Residual Auction
CC	Combined cycle
COD	Commercial Operation Date
CONE	Cost of New Entry
CT	Combustion Turbine
DAM	Day Ahead Market
DG	Distributed Generation
DR	Demand Response
EDC	Electric Distribution Company
EDECA	Electric Discount and Energy Competition Act
EE	Energy Efficiency
EMAAC	Easter Mid-Atlantic Area Council
EMP	Energy Master Plan
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FRR	Fixed Resource Requirement
GT	Gas turbine
GW	Gigawatt
GWh	Gigawatt hour
HEDD	High Energy Demand Day
ICAP	Installed Capacity
ISO	Independent System Operator
KW	Kilowatt
KWh	Kilowatt hour
LCAPP	Long Term Capacity Agreement Pilot Program
LDA	Locational Deliverability Area
LMP	Locational Marginal Price
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council
MAAP	Mid-Atlantic Power Pathway
MOPR	Minimum Offer Price Rule
MW	Megawatt
MWh	Megawatt Hour
NEPA	New Entry Price Adjustment
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
P3	PJM Power Providers Group

PATH	Potomac-Appalachian Transmission Highline
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
RCP	Resource Clearing Price
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTM	Real Time Market
RTO	Regional Transmission Organization
SIS	System Impact Study
SOCA	Standard Offer Capacity Agreement
TO	Transmission Owner
TRAIL	Trans-Allegheny Interstate Line
TRC	Total Resource Cost
UCAP	Unforced Capacity
VRR	Variable Resource Requirement