Regional Planning Process Task Force Interim Report

Market Efficiency Proposal Report
Multi-Driver Status Report
Order 1000 Status Report
May 22, 2013

RPPTF Summary Scope & Charter

The RPPTF was established to:

1. Evaluate the need to expand the transmission planning criteria, or existing scenario planning procedures to include a broader range of assumptions, and
2. Develop the processes to receive and consider alternate transmission proposals, prioritize and choose among competing projects and designate entities (incumbents and or new entrants) to construct, own, operate and maintain baseline RTEP upgrades, and
3. Evaluate and make recommendations to implement additional planning criteria or procedures to include a broader range of assumptions that would be required to plan for public policy initiatives such as renewable resource integration, demand response programs, or other environmental initiatives, and
4. In the event additional planning criteria is proposed to address public policy initiatives, the RPPTF will assess the impact of the proposed criteria on the current interconnection queuing processes and procedures and make recommendations as required, and
5. Evaluate and make recommendations on modifying or expanding PJM criteria or procedures related to "at risk" generation in the RTEP.

RPPTF Interim Report

The following report encompasses:

1. Market Efficiency Proposal Report - Modeling Recommendations – the report provides the results of the RPPTF efforts to examine the modeling criteria employed in the Market Efficiency Benefit Determination, the proposed revisions to the modeling assumptions for Market Efficiency regarding generator expansion and proposed revisions of the PJM definition for "production cost." ***These items and recommendations are submitted to the MRC on a first read basis for the May 30th MRC Meeting with anticipated voting at the June 27th MRC Meeting.***

2. Multi-Driver Approach (MDA) Status Report – the RPPTF has concluded a non-binding poll on revisions to adopt a potential MDA including public policy projects and associated cost apportionment methods. ***A formal RPPTF vote will be undertaken shortly and the results forwarded to the MRC for consideration and vote.***

3. Order 1000 Status Report – PJM Staff and RPPTF Stakeholders have continued efforts at both RPPTF and joint, interregional meetings regarding current compliance efforts with FERC Order No. 1000. ***This report provides current status and is informational in nature.***

1. Market Efficiency Proposal Report & Main Motion

The PJM RPPTF has vetted several Market Efficiency changes associated with the Benefit determination and the assumptions about adding future generation to the Market Efficiency model to ensure adequate supply of generation to meet the PJM reserve requirement. The design elements are described below.

The PJM Market Efficiency process measures the economic benefits of new transmission enhancements along with modifications and accelerations of approved RTEP projects. This process involves measuring the benefit of projects through an hourly unit commitment dispatch simulation to measure the production costs and load payment savings and comparing to the cost of the proposed project over a 15-year period. Recently, the cost allocation for Market Efficiency projects has changed and PJM members decided to explore changes in the Market Efficiency Benefit determination to match closer with the new cost allocation. Many design packages were considered and ultimately two packages were voted on at the RPPTF. These packages along with the existing Market Efficiency cost allocation and benefit determination (status quo), are shown in the below table.

	Existing Cost Allocation: Market Efficiency Projects.	Existing Benefit Determination: May 2013	Benefit Determination Package 4	Benefit Determination Package 10
Regional Projects	50% Load Ratio Share and 50% to zones with decreased net load payments	Total Benefit= Energy + Capacity Benefit		
		Energy Benefit: 70% change in production costs + 30% change in net load payments all zones	Energy Benefit: 50% change in production costs + 50% change in net load payments all zones	Energy Benefit: 50% change in production costs + 50% change in net load payments (only zones with decrease in net load payments)
		Capacity Benefit: 70% change in capacity costs + 30% change in net capacity payments all zones	Capacity Benefit: 50% change in capacity costs + 50% change in net capacity payments all zones	Capacity Benefit: 50% change in capacity costs + 50% change in net capacity payments (only zones with decrease in net capacity payments)
Lower Voltage Projects	100% to zones with decreased net load payments	Total Benefit= Energy + Capacity Benefit		
		Energy Benefit: 70% change in production costs + 30% change in net load payments(only zones with decrease in net load	Energy Benefit: 50% change in production costs + 50% change in net load payments(only zones with decrease in net load	Energy Benefit: 100% change in net load payments (only zones with decrease in net load payments)
		Capacity Benefit: 70% change in capacity costs + 30% change in net capacity payments (only zones with decrease in net capacity payments)	Capacity Benefit: 50% change in capacity costs + 50% change in net capacity payments (only zones with decrease in net capacity payments)	Capacity Benefit: 100% change in net capacity payments (only zones with decrease in net capacity payments)

The benefit determination for Package 4 and Package 10 are similar for regional projects except for Package 10 the change in net load/capacity payments only includes zones with a decrease in net load/capacity payments. Therefore, for Package 10 the PJM zones which show a increase in net load/capacity payments as a result of the studied project will not be included in the benefit determination for regional projects. This method of using 50% of the net load/capacity payments for zones with a decrease in net load/capacity payments is consistent with the cost allocation for regional projects for Market Efficiency. The benefit measurement for Lower Voltage Projects is the same for both Package 4 and Package 10 except in Package 10 the production costs metric is not used. Therefore, the benefit determination for Package 10 for Lower Voltage Projects is similar to the cost allocation for Lower Voltage Projects.

<u>Voting/Polling Results for Market Efficiency Benefit Determination</u>

- Status quo – non-binding informational poll of voting respondents. The poll had 38 respondents polling for and 93 against maintaining the status quo. (29% Support for Status Quo). ***The polling results suggest low support for the current method.***

- Package 4 – Binding vote of eligible members. The vote had 43 respondents voting for and 70 against Package 4 (38.1% support for Package 4). ***The voting results do not qualify as a main or alternative motion.***

- Package 10 – Binding vote of eligible members. The vote had 115 respondents voting for and 18 against Package 10 (86.5% support for Package 10). ***The voting results qualify as the main motion.***

- ***Package 4 did not receive at least 50% support and will not move forward to the MRC. Package 10 received a majority support and represents the main motion proposed for vote at the MRC. The RPPTF recommends MRC endorsement of Package 10 as well as corresponding revisions to the PJM Operating Agreement and PJM Manuals to implement the proposed changes.***

2. <u>Market Efficiency - Generator Expansion Assumptions</u>

The RPPTF also explored changes to the methods in which PJM adds generation in the Market Efficiency Simulations. Current market efficiency procedures evaluate the impact of a project over the 15-year planning horizon. Typically, when comparing the PJM forecasted load against the forecasted generation supply, an Installed Reserve Margin (IRM) shortfall will be identified in the latter Market Efficiency study years. Currently, it is assumed that the projected generation supply will grow in order to at least maintain the forecasted IRM. Therefore, PJM currently scales existing units in later study years in order to meet the forecasted IRM. Active generation queue projects that are not part of the unit specific plan are eligible to impact the location and type of generation that gets scaled for meeting the PJM reserve margin. The capacity values of the remaining queue projects are aggregated by unit type and region to determine a percentage by region and unit type that is the basis for unit scaling. The existing unit specific plan includes existing PJM units as well as units that have, at a minimum, an executed Interconnection Service Agreement (ISA). The RPPTF explored changes to the method to account for new projected generation supply for study years in which the IRM is not met. These methods are summarized below:

Design Elements A+D

- Design Element A (Status Quo): Include all ISA. Scale existing units based on location and technology to meet Reserve Requirement
- Design Element D: Include actual transmission upgrades for congestion that arises from scaling assumptions.

Design Elements B+D (PJM Recommended)

- Design Element B: Include all ISA and FSA. Scale existing units based on location and technology to meet Reserve Requirement. Review of FSA units for exceptions.
- Design Element D: Include actual transmission upgrades for congestion that arises from scaling assumptions.

Design Elements D+G

- Design Element D: Include actual transmission upgrades for congestion that arises from scaling assumptions.
- Design Element G: Include all ISA. Add units on HV system based on location and technology to meet Reserve Requirement.

Design Element A is the status quo. Design Element B is an extension to the status quo and involves including units that have executed a Facility Study Agreement (FSA) in the unit specific Market Efficiency simulations. The inclusion of FSA units will reduce the amount of scaling necessary to meet the PJM IRM. Inclusion of FSA units for Market Efficiency is also consistent with the assumptions used in reliability analysis and is supported with transmission upgrades being modeled that are necessary for the units identified in the FSAs. Design Element D involves the inclusion of transmission upgrades that may arise from the scaling of existing units for later study years in which the unit specific plan is not sufficient to meet the IRM. Finally, Design Element G is similar to the status quo but instead of scaling existing units to meet the IRM for necessary study years, new units would be added to the high voltage system based on location and technology. Design Elements B and D grouped as a package received the majority vote at the RPPTF and will move forward to the MRC. All other Design elements as shown above did not receive a majority support and will not move forward to the MRC.

Voting/Polling Results for Market Efficiency Modeling of Generator Expansion

- Status quo – non-binding informational poll of voting respondents. The poll had 1 respondent polling for and 113 respondents against maintaining the status quo. (<1% Support for Status Quo). ***The polling results suggest virtually no support for the current method.***

- Elements A+D – Binding vote of eligible members. The vote had 14 respondents voting for and 109 respondents against Elements A+D (11.4% support Elements A+D). ***The voting results do not qualify as a main or alternative motion.***

- Elements B+D – Binding vote of eligible members. The vote had 123 respondents voting for and 1 respondent against Elements B+D (99.2% support for Elements B+D). ***The voting results qualify as the main motion.***

- Elements D+G – Binding vote of eligible members. The vote had 1 respondent voting for and 104 respondents against Elements D+G (<1% support for Elements D+G). ***The voting results do not qualify as a main or alternative motion.***

- ***Neither Elements A+D nor D+G received at least 50% support and, therefore, will not move forward to the MRC.***

- ***In addition to the elements listed above, the RPPTF discussed and recommended the following principles be adhered to regarding implementation of*** **Elements B+D:**

    - PJM shall identify proposed FSA units for inclusion/removal from the modeling simulations

    - PJM shall share the proposed list of FSA units with TEAC stakeholders. Additionally, the topic would be included on a scheduled TEAC agenda to promote transparency and allow for informed discourse prior to PJM setting the modeling assumptions

    - Resultant PJM data, analysis and reports shall denote FSA units included in the models

    - These measures were requested to ensure that modeling results would not be skewed by a generator (or generators) perceived to be subject to significant delay or potential regulatory/siting risks.

- ***Elements B+D received a majority support and represents the main motion proposed for vote at the MRC. The RPPTF recommends MRC endorsement of Elements B+D as well as corresponding revisions to the PJM Operating Agreement and PJM Manuals to implement the proposed changes.***

3. Market Efficiency - Proposed Revisions to "Production Cost" Definition

The RPPTF also evaluated whether to propose revision of the definition of production cost. Currently, the definition limits the market efficiency simulations to consider only internal purchases and sales. This approach does not accurately take into account those cross border transactions with neighboring ISOs/RTOs. If the following revisions are ultimately endorsed, PJM staff would be able to set simulation program parameters to incorporate selected regions/lines in its analyses. With the understanding that the settings within the simulation software for each of the published cases would be documented and shared for transparency with stakeholders, the RPPTF achieved a Tier 1 Consensus for the proposed revision.

The Production Cost definition with proposed revisions in red follow:

"Estimated total annual fuel costs, variable O&M costs, and emission costs of the dispatched resources in the PJM Region. Costs for purchases from outside of the PJM area and sales to outside the PJM area will be

captured if appropriate. Purchases will be valued at the Load Weighted LMP and sales will be valued at the Generation Weighted LMP."

Tier 1 Consensus was achieved at December 2012 RPPTF Meeting and re-confirmed at the May 6th meeting.

The definition above represents the main motion proposed for vote at the MRC. The RPPTF recommends MRC endorsement of the proposed definition revision as well as corresponding revisions to the PJM Operating Agreement and PJM Manuals to implement the proposed changes.

4. Multi-Driver Approach Status Report

Background – PJM currently has established processes for evaluating the potential combination of Reliability (R) and Market Efficiency (ME) projects to ensure a reliable, cost effective transmission grid spanning the PJM region.

Over the past several months, the Regional Planning Process Task Force has considered, discussed and debated a number of factors relating to refining PJM's transmission planning processes. Specifically – the task force has considered methods for inclusion of Public Policy (PP) projects and whether a formal Multi-Driver Approach that incorporates PP projects should be adopted.

On May 14th, the RPPTF concluded a non-binding poll on adoption of an integrated Multi-Driver Approach and proposed methods of cost apportionment. The results of the poll follow:

- Multi-Driver Approach – non-binding poll of RPPTF stakeholders. The poll had 112 respondents voting for and 16 respondents against implementation of a multi-driver approach that provides for integration of public policy projects (87.5% support).
- Incremental cost apportionment for <u>combinations of R, ME and PP projects</u> – non-binding poll of RPPTF stakeholders. The poll had 109 respondents voting for and 19 respondents against implementation of a cost allocation approach that provides for incremental treatment of public policy projects when combined with R and or ME projects (85.2% support incremental).
- Proportional cost apportionment for a <u>completely separate multi-driver solution</u> that replaces proposed R, ME and PP projects – non-binding poll of RPPTF stakeholders. The poll had 104 respondents voting for and 19 respondents against implementation of a cost allocation approach that provides for proportional treatment of a completely separate multi-driver solution (81.3% support proportional).
- ***The polling results demonstrated support for a multi-driver approach that provides for integration of public policy projects and offered direction for cost apportionment methods for different solutions incorporating R, ME and PP projects. At the May 22nd meeting, the RPPTF was asked whether a Tier 1 Consensus might be evident. Two parties objected and therefore, the unanimity requirement was not met. Having no proposed alternatives, a Tier 2 Consensus could not be pursued, leaving the matter for formal vote. After discussion, it was determined***

that clarification and education on the status quo was necessary. PJM is preparing a draft voting instrument which will include an explanation of the status quo, the formal voting questions and a poll on the status quo.

The MDA vote will be completed and results provided to the MRC. There is no MRC action at this time.

FERC Order 1000 Status Report

PJM made a Compliance filing in October of 2012 and, on March 22, 2013, the Commission issued its Order on PJM's Order No. 1000 Compliance Filing requiring PJM to submit certain compliance filings within 120 days of the March 22 Order or no later than July 22, 2013. As part of preparations for PJM's response, the RPPTF has been discussing and sharing positions.

Additionally, on February 26, 2013, the Commission issued a notice extending the time to submit Order No. 1000 interregional compliance filings until July 10, 2013 for all transmission providers. PJM Staff and RPPTF stakeholders have been participating in joint sessions with neighboring regions and working toward developing filing materials to be submitted to FERC on July 10, 2013. The following is a summary of progress and key issues for MRC informational purposes. ***No voting is planned for this item.***

- PJM/NYISO – The current PJM/NYISO JOA provides for interregional planning through the Northeastern ISO/RTO Planning Coordination Protocol (Protocol). The Protocol is a three party Agreement between PJM, NYISO and ISO-NE. Enhancements to the Protocol, that are consistent with the requirements of Order No. 1000 have been drafted and been reviewed with stakeholders. In addition to the Northeast Planning Protocol, changes to the PJM/NYISO JOA are also being considered.

- PJM/MISO – Article IX of the MISO/PJM JOA provides for coordinated regional transmission expansion planning and includes provisions for administration of planning activities, data and information exchange, coordinated system planning and allocation of cost for both reliability and market efficiency projects. Enhancements to Article IX of the JOA have been drafted and reviewed with stakeholders. Recently, MISO took the position that the criteria for cross border reliability projects along with the associated provisions for cross border reliability project cost allocation, should be removed from the Agreement. PJM does not agree with the MISO position. Discussions between PJM and MISO on the matter are continuing.

- PJM/SERTP - PJM has also been having discussions with the Southeast Regional Transmission Planning (SERTP) region related to FERC Order No. 1000 compliance. A strawman for compliance with the Order has been developed. Revisions to the tariff that are consistent with the compliance strawman are being drafted. PJM does not plan to supersede the existing joint operating agreements entered into with its neighbors.

5. Appendix I: Supplemental Documents

- DRAFT PJM Operating Agreement (OA) Redline

6. Appendix II: Stakeholder Participation

Last Name	First Name	Company Name	Sector
Ainspan	Malcolm	Energy Curtailment Specialists, Inc.	Other Supplier
Alston	Rick	Old Dominion Electric Cooperative	Electric Distributor
Anders	David	PJM Interconnection	Not Applicable
Barker	Jason	Exelon Energy	Transmission Owner
Barone	Richard	Navigant Consulting, Inc.	None
Bastian	Jeff	PJM Interconnection	Not Applicable
Batta	Michael	Virginia Electric & Power Company	Transmission Owner
Bearden	Joel	Cargill Power Markets LLC	Other Supplier
Berman	Emily	Unknown	None
Bhavaraju	Murty	PJM Interconnection	Not Applicable
Bloom	David	Baltimore Gas and Electric Company	Transmission Owner
Bolan	Martin	FirstEnergy Solutions Corporation	Transmission Owner
Borchers	Dylan	Bricker	Not Applicable
Bowring	Joe	Monitoring Analytics, LLC	Not Applicable
Breidenbaugh	Aaron	EnerNOC, Inc.	Other Supplier
Brodbeck	John	Potomac Electric Power Company	Electric Distributor
Bruce	Susan	McNees Wallace & Nurick LLC	Not Applicable
Callis	Joseph	PJM Interconnection (Facilitator)	Not Applicable
Campbell	Bruce	EnergyConnect, Inc.	Other Supplier
Canter	David	AEP	Transmission Owner
Carmean	Gregory	OPSI	Not Applicable
Carretta	Kenneth	PSE&G ER&T	Transmission Owner
Citrolo	John	PSE&G ER&T	Transmission Owner
Coulbeck	Rob	ENBALA Power Networks Inc.	Other Supplier
Covino	Susan	PJM Interconnection	Not Applicable
Cox	Jason	Dynegy Power Marketing, Inc.	Generation Owner
David “Scarp”	Scarpignato	Direct Energy Business, LLC	Other Supplier
Dean	Kevin	McNees Wallace & Nurick LLC	Not Applicable

DeGeeter	Ralph	Maryland Public Service Commission	Not Applicable
DeNavas	Joe	Potomac Electric Power Company	Electric Distributor
Desmarais	Michael	EnerNOC, Inc.	Other Supplier
Dimailig	Josh	AEP Energy Partners, Inc.	Other Supplier
Dorn	Andrew	Demand Response Partners	Curtailment Service Provider
Dugan	William	Market Monitoring Unit	Not Applicable
Eakin	Brian	Navigant Consulting, Inc.	None
Ellis	Jeff	Edison Mission Marketing and Trading	Transmission Owner
Esposito	Patricia	NRG Power Marketing LLC	Generation Owner
Esterly	Teri	PJM Interconnection	Not Applicable
Farber	John	DE Public Service Commission	Not Applicable
Feliks	Kent	American Electric Power	Transmission Owner
Fereshetian	Damon	Viridity Energy, Inc.	Other Supplier
Filomena	Guy	Customized Energy Solutions, Ltd.*	Not Applicable
Fitch	Neal	GenOn Energy Management, LLC	Generation Owner
Flaherty	Dale	Duquesne Light Company	Transmission Owner
Ford	Adrien	PJM Interconnection	Not Applicable
Fraley	Craig	Allegheny Power	Transmission Owner
Gilani	Rehan	ConEdison Energy, Inc.	Other Supplier
Gilkey	Rick	Customized Energy Solutions, Inc.	Not Applicable
Gockley	Beatrice	EnergyConnect	Other Supplier
Godson	Gloria	Potomac Electric Power Company	Transmission Owner
Greening	Michele	PPL EnergyPlus, L.L.C.	Transmission Owner
Griffiths	Daniel	Enerwise Global Technologies, Inc.	Other Supplier
Guerry	Katie	Hess Corporation	Other Supplier
Habre	Alex	PJM Interconnection	Not Applicable
Hall	Walter R.	Maryland Public Service Commission	Not Applicable
Hewett	Christophe r	Virginia Electric and Power Company	Transmission Owner
Hoatson	Tom	Riverside Generating, LLC	Other Supplier
Horstmann	John	Dayton Power & Light Company (The)	Transmission Owner

Howley	Rachel	Hess Corporation	Other Supplier
Huntoon	Stephen	NextEra Energy Power Marketing, LLC	Generation Owner
Irwin-Wedbush	Craig	Unknown	None
Jennings	Ken	Duke Energy	Power Marketer
jones	kim	North Carolina Utilities Commission	Not Applicable
Kerecman	Joseph	Calpine Energy Services	Generation Owner
Kogut	George	FirstEnergy Solutions Corporation	Transmission Owner
Kopon	Owen	Brickfield, Burchett, Ritts, and Stone, PC	Not Applicable
Krajnik	Gregory	Viridity Energy, Inc.	Other Supplier
Langbein	Pete	PJM Interconnection	Not Applicable
Leyko	James	Maryland Public Service Commission	Not Applicable
Lieberman	Steve	Old Dominion Electric Cooperative	Electric Distributor
Lindeman	Tony	First Energy Solutions Corporation	Transmission Owner
Lukach	Jaclynn	PJM Interconnection (Secretary)	Not Applicable
Mabry	Dave	PJM Industrial Customer Coalition	Not Applicable
Mahoney	Julia	New York State Electric & Gas Corporation	Other Supplier
Mancuso	Maria	Baltimore Gas and Electric Company	Transmission Owner
Mariam	Yohannes	Office of the Peoples Counsel for the District of Columbia	Not Applicable
Martin	Valerie	The Federal Energy Regulatory Commission	Not Applicable
Marton	David	FirstEnergy Solutions Corp.	Power Marketer
Marzewski	Skyler	Monitoring Analytics	Not Applicable
Maucher	Andrea	Division of the Public Advocate of State of Delaware	Not Applicable
Maye	Shelly-Ann	North America Power Partners LLC	Other Supplier
McCartha	Esrick	PJM Interconnection	Not Applicable
McDonald	Steve	Customized Energy Solutions, Ltd.*	Not Applicable
Mendelsohn	Mark	Noble Americas Gas & Power Corp.	Other Supplier
Miller	Don	FirstEnergy Solutions Corporation	Transmission Owner
Miller	John	Commonwealth Edison Company	Transmission Owner
Millien	Sachiel	Noble Americas Gas & Power Corp.	Power Marketer
Mosier	Kevin	Maryland Public Service Commission	Not Applicable
Moss	James	Monitoring Analytics	Not Applicable
Moss	Skip	Syntil, Inc	None

Nguyen	John	Northern Virginia Electric Cooperative (NOVEC)	Electric Distributor
Norton	Chris	American Municipal Power, Inc.	Electric Distributor
Nowell	Cynthia	Potomac Electric Power Company	Transmission Owner
Nowicki	Linda	New Jersey Board of Public Utilities	Not Applicable
O'Neill	Jack	PJM Interconnection	Not Applicable
Ondayko	Brock	Appalachain Power Company (AEP)	Transmission Owner
Pasupatham	Ramaswamy	Exelon Generation Co., LLC (ComEd CPP Annual)	Transmission Owner
Pengidore	Carolyn	NRG Energy	Generation Owner
Peters	James	The Federal Energy Regulatory Commission	Not Applicable
Pieniazek	Marie	Energy Curtailment Specialist, Inc	Other Supplier
Polakowski	Ray	Hess Corporation	Other Supplier
Poulos	Greg	EnerNoc, Inc	Other Supplier
Powers	Sean	Linde Energy Services, Inc.	End Use Customer
Pratzon	David	GT Power Group	Not Applicable
Price	Dann	Constellation NewEnergy, Inc.	Other Supplier
Quinlan	Pamela	Rockland Electric Company	Transmission Owner
Renninger	Matt	Energy Curtailment Specialists, Inc.	Other Supplier
Rutigliano	Tom	Constellation NewEnergy, Inc.	Other Supplier
Sailers	Bruce	Duke Energy	Power Marketer
Schofield	William	Customized Energy Solutions, Inc.	Not Applicable
Shissler	Ken	EnerNoc, Inc	Other Supplier
Simms	Chris	North America Power Partners LLC	Other Supplier
Smith	Thomas	City of Cleveland, DPU, Division of Cleveland Public Power	Electric Distributor
Sotkiewicz	Paul	PJM Interconnection	Not Applicable
Stadelmeyer	Rebecca	Exelon Business Services Company, LLC	Transmission Owner
Stein	Ed	FirstEnergy Solutions Corporation	Transmission Owner
Stuchell	Jeff	FirstEnergy Solutions Corporation	Transmission Owner
Sudhakara	Raghu	Rockland Electric Company (CIEP Load)	Transmission Owner
Suh	Jung	Noble Americas Energy Solutions LLC	Other Supplier
Swalwell	Brad	Tangent Energy	Other Supplier

Thompson	Matt	North America Power Partners LLC	Other Supplier
Trayers	Barry	Citigroup Energy, Inc.	Other Supplier
Trott	Jeff	Galt Power	Other Supplier
Walker	William	PJM Interconnection	Not Applicable
Watson	Jeanine	PJM Interconnection	Not Applicable
Wehr	Chris	Metropolitan Edison Company	Transmission Owner
Wiegand-Jackson	Laurie	North America Power Partners LLC	Other Supplier
Wilmoth	Emily	Dominion Virginia Power	Not Applicable
Wisersky	Megan	Madison Gas & Electric Co	Other Supplier
Wolfe	Samuel	Viridity Energy, Inc.	Other Supplier
Worthem	Dennis	Sierra Globe	None

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