The Energy Bar Association

Northeast Chapter Annual Meeting

June 5, 2013
The Newark Club
1 Newark Center, 22nd Fl.
Newark, NJ 07102
The Energy Bar Association is committed to the goals of fostering an inclusive and diverse membership and increasing diversity across all levels of the Association, so as to reflect the diversity of the energy industry and the Nation as a whole. Attorneys, non-attorney professionals in the energy field and law students are welcome to join our ranks regardless of race, creed, color, gender, ethnic origin, religion, sexual preference, age, or physical disability and are encouraged to become active participants in the Association’s activities.
Exploring New Trends and Emerging Issues Facing the Energy Industry

Join us to explore new trends and emerging issues facing the energy industry. Our four panels will explore critical issues facing energy practitioners in the Northeast.

PROGRAM SCHEDULE

**WEDNESDAY, JUNE 5, 2013**

<table>
<thead>
<tr>
<th>Time</th>
<th>Event</th>
<th>Speakers</th>
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<tr>
<td>8:00 a.m.</td>
<td><strong>REGISTRATION</strong></td>
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| 8:30 a.m. | **WELCOME**                               | Tamara L. Linde  
President, Northeast Chapter  
PSEG  
Adrienne E. Clair  
President, Energy Bar Association  
Stinson Morrison Hecker LLP                                                                                   |
| 8:45 - 9:10 a.m. | **INDUSTRY UPDATE**                 | Ralph Izzo  
Chairman of the Board, President and Chief Executive Officer  
Public Service Enterprise Group                                                                                   |
| 9:10 a.m. | **KEYNOTE ADDRESS**                       | Cory Booker  
Mayor of Newark, NJ                                                                                         |
| 9:30 - 10:45 a.m. | **Super Storm Sandy- Lessons Learned and Next Steps** |                                                                                                    |
| 10:45 a.m. | **NETWORKING BREAK**                      |                                                                                                    |
| 11:00 a.m. | **Planning the System to include Wind If we build it will they come?** |                                                                                                    |
| 11:00 - 12:15 p.m. | **If we build it will they come?** | Increased renewable energy provides many benefits but the costs to expand and update the grid to accommodate may be very high. To what degree should system operators be building/planning transmission facilities to facilitate the growth of renewable generation, including off-shore wind? This panel will explore whether we should be building such facilities and how the costs should be allocated.  
Moderator: Richard Miller  
Con Edison  
Panelists: Stefanie A. Brand  
Director, Division of Rate Counsel  
State of New Jersey  
Michael J. Kormos  
Senior Vice President of Operations  
PJM  
Ralph LaRossa  
President and Chief Operating Officer  
Public Service Electric and Gas Company                                                                                   |

Super Storm Sandy hit the northeast on October 29, 2012 and caused tens of billions of dollars in damage, destroyed thousands of homes, left millions without electric service and other critical services for prolonged periods of time. This panel will explore the lessons learned from the storm and its aftermath and the steps that should be taken to prepare for the future.

Moderator: Tamara L. Linde  
PSEG  
Panelists: Robert M. Hanna  
President  
Board of Public Utilities
**LUNCH & LUNCHEON SPEAKER**

12:15 - 1:30 p.m.

The Honorable John R. Norris
Commissioner
Federal Energy Regulatory Commission

**FERC Enforcement and Compliance**

Fraud and market manipulation are among the top priorities for FERC’s Office of Enforcement, and the Commission has now settled a number of investigations involving its anti-manipulation authority. This panel will explore emerging themes and lessons learned from recent FERC market manipulation enforcement actions and settlements, along with potential challenges for market participants and compliance programs.

Moderator: Larry D. Gasteiger
Federal Energy Regulatory Commission

Panelists:
- Larry Parkinson
  Director, Division of Investigations
  Federal Energy Regulatory Commission
- Robert S. Fleishman
  Covington & Burling LLP
- Shari Gribbin
  Manager, FERC Compliance & Assistant General Counsel
  Exelon Business Services Company
- The Honorable Joseph T. Kelliher
  Executive Vice President, Federal Regulatory Affairs, Next Era and Former Chairman
  Federal Energy Regulatory Commission

2:45 - 3:00 p.m.

**NETWORKING BREAK**

3:00 - 4:15 p.m.

Natural Gas Pipelines and the Demands of the Electric Industry

With the advent of low cost Marcellus Shale gas and increasing constraints on the Natural Gas Pipeline system, the Natural Gas industry has been challenged to match their business with the demands of a very different electric industry. This panel will explore the investments and innovations that are underway today in the Natural Gas industry. This panel will also ask how and who should pay for any new infrastructure investments.

Moderator: Michelle Cadin Gardner
Capital Power Corporation

Panelists:
- John P. Rudiak
  Senior Director of Energy Supply
  Connecticut Natural Gas Corporation & Southern Connecticut Gas Company
- Robert B. Stoddard
  Vice President and Practice Leader
  Energy & Environment
  Charles River Associates
- Matthew J. Picardi
  Vice President
  Shell Energy North America (U.S.), L.P.
- Richard J. Kruse
  Vice President, Rates & Regulatory Affairs & FERC CCO
  Spectra Energy

4:15 p.m.

**Concluding Remarks**

4:30 - 6:00 p.m.

**Cocktail Reception and Wine Auction**

Benefit for the Charitable Foundation of the Energy Bar Association with proceeds going to local charity in support of Super Storm Sandy Relief.
We Wish to Thank Our Sponsors
Northeast Chapter Annual Meeting
The Newark Club
Newark, NJ
June 5, 2013

First Rocky Mountain Chapter Annual Meeting
Denver, CO
June 21, 2013

2013 EBA Mid-Year Conference
Renaissance Washington
Washington, D.C.
October 23-24, 2013

2014 EBA Annual Meeting & Conference
Renaissance Washington
Washington, D.C.
April 8-9, 2014

For information on EBA, regional programs, activities and publications, visit www.eba-net.org or call 202/223-5625
Super Storm Sandy:
Lessons Learned and Next Steps

EBA Northeast Chapter Annual Meeting
June 5, 2013
Voluntary Utility
Mutual Assistance

Edward Comer
Vice President, General Counsel
Edison Electric Institute

Energy Bar Association
June 5, 2013
Newark, NJ

BEFORE AND AFTER THE STORM
A Compilation of Storm Response and Resiliency Measures

<table>
<thead>
<tr>
<th>Infrastructure Hardening</th>
<th>Resiliency Measures</th>
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<tbody>
<tr>
<td>• Undergrounding</td>
<td>• Increased labor force</td>
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<tr>
<td>• Vegetation management</td>
<td>• Standby supply of equipment</td>
</tr>
<tr>
<td>• Higher design and construction standards</td>
<td>• E.g. trucks</td>
</tr>
<tr>
<td>• Smart grid</td>
<td>• Restoration materials</td>
</tr>
<tr>
<td>• Microgrid</td>
<td>• Enhanced communications, planning and coordination</td>
</tr>
<tr>
<td>• Advanced Technology</td>
<td>• Advanced Technology</td>
</tr>
<tr>
<td>• E.g. Hydrophobic coating</td>
<td>• E.g. Smart grid</td>
</tr>
<tr>
<td>• Circuit auto-reconfiguration</td>
<td>• Airborne damage assessment</td>
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<tr>
<th>Cost Recovery Mechanisms</th>
<th>State Policies &amp; Company Programs</th>
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<tr>
<td>• Base rates</td>
<td>Cross-section of state approved policies &amp; programs:</td>
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<tr>
<td>• Cost deferral mechanisms</td>
<td>• Northeast</td>
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<tr>
<td>• Rate adjustment mechanisms</td>
<td>• Mid-Atlantic</td>
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<tr>
<td>• Formula rates</td>
<td>• Southeast</td>
</tr>
<tr>
<td>• Storm reserve accounts</td>
<td>• Midwest</td>
</tr>
<tr>
<td>• Securitization</td>
<td>• Western</td>
</tr>
<tr>
<td>• Customer or developer funding/matching contributions</td>
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Storm Response Resources

- **Superstorm Sandy** – October 2012
  - Over 10 million outages along the East Coast
  - 67,000 restoration staff

- **Derecho** – June 2012
  - Approximately 5 million outages in the Ohio Valley and Mid-Atlantic
  - Approximately 30,000 restoration staff

Storm Response Resources

- **Hurricane Irene** – August 2011
  - Approximately 7 million outages on the East Coast
  - Nearly 50,000 restoration staff

- **Hurricane Katrina** – August 2005
  - 2.6 million outages in the Gulf Coast
  - Approximately 46,000 restoration staff
Every electric utility has a detailed plan for restoring electricity after a storm. Typically, one of the first steps a utility takes—to prevent injuries and fires—is to make sure that the power is no longer flowing through downed lines. Restoration then proceeds based on established priorities.
How Does the Mutual Assistance Network Work?

- Voluntary partnership of utilities that send skilled line workers to areas affected by major outages
- **Regional Mutual Assistance Groups** (RMAGs)
  - Assist in coordinating restoration efforts
  - Locate and send equipment, materials, skilled and specialized workers
  - Line crews
  - Tree trimmers
  - Damage assessors
  - Logistics managers

Regional Mutual Assistance Groups

- Wisconsin Utilities Association Mutual Assistance Group
- Midwest Mutual Assistance Group
- Mid-Atlantic Mutual Assistance Group
- Northeast Mutual Assistance Group
- Great Lakes Mutual Assistance Group
- Western Region Mutual Assistance Agreement
- Texas Mutual Assistance Group
- Southeastern Electric Exchange
- New York Mutual Assistance Group
EEI’s Mutual Assistance Network

- Formed in 1955: Comparable public power and coop groups
- Helps share the risks and costs of restoring power after major outages
- Provides competent, trained employees and contractors
- Shares best practices
- Separate arrangement for Spare Transformers

EEI’s Mutual Assistance Network

- Legal agreement has principles that address basic issues:
  - payment,
  - liability,
  - wages,
  - management control,
  - arrangements for housing, food, equipment, supplies,
  - applicable safety rules.
Superstorm Sandy: A Public-Private Partnership

- EEI convenes CEO Coordination calls.
- President Obama calls for “no bureaucracy, no red tape.” His discussion with CEOs initiates unprecedented public/private coordination on power restoration.
- The federal government for the first time brought electric utility representatives into FEMA headquarters and a federal interagency task force.
- EEI and other electric power providers coordinated the industry’s response with the White House and FEMA, DOE, DOD, DHS, DOT.
Superstorm Sandy: A Public-Private Partnership

- Coordination with the Federal Government
  - Daily CEO conference calls with federal government agencies and daily federal agency calls
  - Transportation for expeditious arrival and return (e.g., weigh station stops, state fuel tax and registration rules, airlifts, tolls, escorts)
- Logistics (e.g., equipment, supplies, fuel, lodging for thousands of people)
- Security (e.g., utility responder/customer protection, road clearance)
- International challenges (i.e., utility responder border crossings)

Superstorm Sandy: A Public-Private Partnership

- December 2012 follow-up meetings with DOE and other industry and federal representatives to begin a post-Sandy examination including:
  - Major challenges
  - Areas needing improvement
  - What worked well (e.g., notable successes, identify best practices, lessons learned)
  - Recommended near- and long-term preparedness action
- DOE and FEMA to issue recommendations
Institutionalizing Lessons Learned From Federal Partnership

- Identify appropriate threshold or “trigger” for any future coordination
- Transportation (tolls, weigh stations, permit waives/extensions)
- Logistics (equipment, supplies, fuel, lodging)
- Security (utility responder/customer protection, road clearance)
- Telecommunications (equipment, facilities, spectrum)
- Cost share / recovery – Stafford Act Limitations
- International challenges (expedite travel thru U.S. points of entry)
- Customer communications
- Customer Reconnection/Electricians

EEI Priorities

- Mutual Assistance and Restoration
  - RMAG configuration & coordination
- Spare equipment and Materials
- Contractors
- Communication
- Best Practices
Lessons Learned/Best Practices

- **Operational**, e.g.
  - Switching & tagging
  - Identify and isolate damage

- **Logistics**, e.g.
  - Lodging
  - Food
  - Laundry
  - Fueling supply & security
  - Staging

Lessons Learned/Best Practices

- **Organizational**, e.g.
  - Utilize non-T&D personnel
  - Community liaison

- **Execution**, e.g.
  - Use new technology
  - Better restoration estimates
  - Estimating ETR
Hard Questions for all Stakeholders To Consider

- How hardened and resilient should the system be?
- What are customers willing to pay for? And when?
- Balancing Local, Regional and Inter-Regional Needs

Before and After the Storm

- Collection of publicly-available studies on hardening and resiliency
- Cost recovery mechanisms
- State regulatory and legislative actions
- Menu of options for utilities and regulators to examine – what works best for them
Storm Hardening Initiatives

Robert Schimmenti
VP Engineering and Planning
Consolidated Edison Company of New York, Inc.
June 5th, 2013

East 14th Street and Avenue C
Sandy Impact

<table>
<thead>
<tr>
<th>Region</th>
<th>Customer Outages</th>
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<tbody>
<tr>
<td>Bronx</td>
<td>75,406</td>
</tr>
<tr>
<td>Brooklyn</td>
<td>143,088</td>
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<tr>
<td>Queens</td>
<td>160,893</td>
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<tr>
<td>Staten Island</td>
<td>179,530</td>
</tr>
<tr>
<td>Manhattan</td>
<td>235,451</td>
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<tr>
<td>New York City Total</td>
<td>794,368</td>
</tr>
<tr>
<td>Westchester County</td>
<td>320,926</td>
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<tr>
<td>Con Edison System Total</td>
<td>1,115,294</td>
</tr>
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</table>
### Historical Storm Comparison

<table>
<thead>
<tr>
<th>Date</th>
<th>Type of Storm</th>
<th>Customers Interrupted</th>
</tr>
</thead>
<tbody>
<tr>
<td>29-Oct-12</td>
<td>Super storm Sandy</td>
<td>1,115,000 *</td>
</tr>
<tr>
<td>28-Aug-11</td>
<td>Hurricane Irene</td>
<td>203,821</td>
</tr>
<tr>
<td>13-Mar-10</td>
<td>Nor'easter</td>
<td>174,800</td>
</tr>
<tr>
<td>29-Oct-11</td>
<td>Nor'easter</td>
<td>135,913</td>
</tr>
<tr>
<td>9-Sep-85</td>
<td>Hurricane Gloria</td>
<td>110,515</td>
</tr>
<tr>
<td>2-Sep-06</td>
<td>Tropical Storm Ernesto</td>
<td>78,300</td>
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<tr>
<td>25-Feb-10</td>
<td>Snow</td>
<td>65,200</td>
</tr>
<tr>
<td>18-Jan-06</td>
<td>Wind / Rain</td>
<td>61,486</td>
</tr>
<tr>
<td>31-Mar-97</td>
<td>Nor'easter</td>
<td>45,180</td>
</tr>
<tr>
<td>19-Oct-96</td>
<td>Nor'easter</td>
<td>41,830</td>
</tr>
</tbody>
</table>

*Note: includes Nor'easter Athena

### Impact of Sandy on Con Edison Facilities

![Image of Con Edison facilities affected by Sandy]
4 Hours of Salt Water Corrosion

Substation Control Circuits
Mutual Aid Crews Arrive From California

Flood Walls Around Control Equipment
Underground Smart Switch

Submersible Transformer Switch
Overhead Distribution Initiatives

- Advanced Equipment
- Selective Undergrounding
- Reduce Segment Size
- Sacrificial Components
- Enhanced Technology

Selective Undergrounding
Storm Hardening Initiatives

Robert Schimmenti
VP Engineering and Planning
Consolidated Edison Company of New York, Inc.
June 5th, 2013
STATE OF NEW JERSEY
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Post Office Box 350
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

IN THE MATTER OF THE BOARD'S ESTABLISHING A
GENERIC PROCEEDING TO REVIEW THE
PRUDENCY OF COSTS INCURRED BY NJ UTILITY
COMPANIES IN RESPONSE TO MAJOR STORM
EVENTS IN 2011 AND 2012

Establishment of a
Generic Proceeding
Docket No. AX13030196

Parties of Record:

Ralph LaRossa, Public Service Electric and Gas Co.
Donald Lynch, Jersey Central Power & Light Co.
Vince Maione, Atlantic City Electric Co.
John McAvoys, Rockland Electric Co.
Tracey Thayer, Esq., New Jersey Natural Gas
Stefanie Brand, Esq., Director, Division of Rate Counsel

BY THE BOARD:

The Board of Public Utilities ("Board") is empowered to ensure that regulated public utilities provide safe, adequate and proper service to the citizens of New Jersey. N.J.S.A. 48:2-23. Pursuant to N.J.S.A. 48:2-13, the Board has been vested by the Legislature with the general supervision and regulation of and jurisdiction and control over all public utilities, "so far as may be necessary for the purpose of carrying out the provisions of [Title 48]." The courts of this State have held that the grant of power by the Legislature to the Board is to be read broadly, and that the provisions of the statute governing public utilities are to be construed liberally. See, e.g. In re Public Service Electric and Gas Company, 35 N.J. 358, 371 (1961); Township of Deptford v. Woodbury Terrace Sewerage Corp. 54 N.J. 418, 424 (1969); Bergen County v. Dept of Public Utilities, 117 N.J. Super. 304 (App. Div. 1971). The Board is also vested with the authority, pursuant to N.J.S.A. 48:2-19, to investigate any public utility, and, pursuant to N.J.S.A. 48:2-15 and 48:2-40, to issue orders to public utilities, and to determine whether the rates charged by public utilities are just and reasonable. N.J.S.A. 48:2-21.

In 2011 and 2012 New Jersey was struck by several extraordinary Major Storm Events which left millions of New Jersey residents without necessary utility service and caused unprecedented damage to the state's utility infrastructure.

MAJOR STORM EVENTS

Hurricane Irene made landfall at Little Egg Inlet as a Category 1 hurricane on Sunday morning
of August 28, 2011. While still out to sea, the storm's outer bands produced heavy rains and wind that battered New Jersey's coastal communities. In addition to the damaging high winds, widespread record setting flooding inundated large portions of the state's utility infrastructure and caused severe damage to both coastal and interior communities. Statewide approximately 1.9 million customers were affected by outages due to this storm. Power was not fully restored until September 5, 2011.

On October 29, 2011 Northern New Jersey was struck with an unseasonal and powerful snowstorm that blanketed the region with record-breaking snowfall. The combination of heavy wet snow and trees mostly full of foliage caused extensive infrastructure damage from fallen trees and limbs. The storm caused loss of electrical service to nearly 1 million of the state's 3.9 million electric customers for up to nine days. Electric service was not fully restored until November 7, 2011.

On June 30 2012, a derecho wind storm left more than 206,000 New Jersey residents without power and caused severe damages large portions of the energy infrastructure in southern New Jersey. The Federal Emergency Management Agency ("FEMA") attributed 34 deaths across the Midwest and Mid-Atlantic regions to the derecho wind storm. Atlantic City Electric ("ACE") deployed over 1,500 personnel in the ensuing restoration effort.

On October 29, 2013, Superstorm Sandy made landfall near Atlantic City New Jersey. Sandy's 90-MPH winds and unprecedented storm surge caused extraordinary and catastrophic damage to dozens of communities across the states. Literally millions of the state's residents were left without, power, water, and natural gas service for extended periods of time following the storm.

Just ten days after Superstorm Sandy, on November 7, 2012, a powerful nor'easter brought significant early season snow fall, damaging winds and tidal-surge to New Jersey. Heavy snowfall caused even further damage to New Jersey's storm-ravaged infrastructure, leaving an additional 167,000 people without power.

As a result of these storms, millions of New Jersey residents were left without electric power, gas service, water and sewer service, often for extended periods of time. Entire communities were disrupted, and their emergency management capabilities were overextended. Schools and businesses were closed and critical facilities activated emergency contingency plans. Due to the widespread and extended outages and the extraordinary efforts required to restore service, the Board considers these storms to qualify as Major Storm Events. As used in this Order, Major Storm Event means sustained impact on or interruption of utility service:

1. resulting from conditions beyond the control of the utility, which may include, but are not limited to, thunderstorms, tornadoes, hurricanes, heat waves, snow and ice storms;
2. which affects at least 10 percent of the customers in an operating area; and
3. due to a utility's documentable need to allocate field resources to restore service to affected areas when one operating area experiences a Major Storm Event, the Major Storm Event shall be deemed to extend to those other operating areas of that utility which are providing assistance to the affected areas.

The Board retains authority to reexamine the characterization of a Major Storm Event.
On January 23, 2013, the Board issued an Order addressing five categories of potential improvements to be undertaken by New Jersey's electric distribution companies ("EDCs") in response to Major Storm Events. These categories include: 1) Preparedness Efforts; 2) Communications; 3) Restoration and Response; 4) Post Event; and 5) Underlying Infrastructure Issues. This Order focuses on the cost expended by all New Jersey Utilities on their Preparedness Efforts, Communications and Restoration and Response to the 2011 and 2012 Major Storm Events.

In the January 23 Order, the Board required the EDCs to take specific actions to improve their preparedness in response to extreme weather events. While restoring utility service to New Jersey's residents is a paramount concern during major storm events, in order to properly discharge its statutory responsibilities and mandate to provide safe, reliable, and affordable utility service, the Board must investigate the prudency of incurred restoration costs.

Accordingly, the Board FINDS that it is critical to investigate the prudency, cost efficiency, and effectiveness of the restoration activities undertaken by the State's utility companies. While the Board ordered the Electric Distribution Companies ("EDCs") to evaluate various storm-related metrics, to properly discharge its statutory responsibilities, and based on the recommendation of Board Staff, as well as comments presented at the public hearings held at various locations across the State, the Board HEREBY FINDS that it is reasonable to initiate a generic proceeding to investigate the prudency of costs incurred by all New Jersey utilities for utility service restoration efforts associated with these Major Storm Events in 2011 and 2012.

ESTABLISHMENT OF A GENERIC PROCEEDING TO EVALUATE PRUDENCY OF MAJOR STORM EVENT RESTORATION COSTS

The Board HEREBY FINDS that it is appropriate to Order utilities subject to Board jurisdiction to submit detailed expense reports clearly identifying all preparation, recovery and restoration costs incurred during these storms including but not limited to utilization of Mutual Aid crews, extraordinary employee deployment costs, facility repair and upgrades and operational steps taken to mitigate damage incurred as a result of a Major Storm Event.

Therefore, the Board HEREBY ORDERS Staff to open a generic proceeding to evaluate and review the prudency of all submissions for Major Storm Event expense reimbursement from ratepayers, filed or to be filed by each utility each under its own separate sub-docket numbered proceeding. Where a utility has already filed a proceeding for recovery or deferral of expenses related to a 2011-2012 Major Storm Event, to the extent that the amount of the allowed recovery has not yet been determined, the Board HEREBY DIRECTS that review of the prudency of those costs shall be conducted within this generic proceeding.

Additionally, the Board HEREBY ORDERS Staff to investigate whether to retain, and the appropriate mechanism to retain, an independent expert to aid the Board in developing standards for examining the prudency of costs incurred by the New Jersey utilities prior to, during and following any Major Storm Event to prevent the loss of, prepare customers for the potential loss of, and restore, utility service.

1 In the Matter of the Board's Review of the Utilities Response to Hurricane Irene, Order Accepting Consultant's Report and Additional Staff Recommendations and Requiring Electric Utilities to Implement Recommendations. BPU Docket No. EO11090543, January 23, 2013 (hereinafter "January 23 Order").
The Board recognizes that maintaining safe, reliable and affordable utility service is the mandate of all New Jersey utilities. Accordingly, the Board HEREBY ORDERS Staff to require that any entity retained by the Board to assist in the evaluation of preparation, recovery and restoration efforts associated with Major Storm Events identify those preparation, recovery and restoration costs that were not included in the utility's Board-approved annual operating expenses standard. The Board continues to recognize that rate impacts to the State's utility ratepayers associated with its decisions must be viewed in concert with the associated benefit of expenditures incurred when preparing for, responding to and restoring the damage caused by any Major Storm Event.

Accordingly, the Board HEREBY ORDERS that, as a condition for approval of the right to recover unreimbursed extraordinary Major Storm Event costs from ratepayers in a currently pending or future base rate filing, all utilities seeking such recovery shall file a detailed report by July 1, 2013 or sooner, including but not limited to, identification of all extraordinary preparation, recovery and restoration costs incurred as a result of the Major Storm Events, such as utilization of Mutual Aid crews, extraordinary employee deployment costs, facility repair and upgrades, and operational steps taken to mitigate damage. The filing shall include the following information:

1) The total of actually incurred unreimbursed, uninsured, incremental storm restoration costs;
2) For each cost identified, information as to the eligibility for, and probability of cost recovery from insurance, any governmental program or any other third party;
3) The costs and ratemaking treatment for those costs for which the company seeks to recover now or in a deferred base rate proceeding;
4) The tax treatment expected for each storm-related cost; and
5) A description of how the company intends to report storm related costs for GAAP purposes.
The Board further **DIRECTS** Staff to evaluate any supplemental information as to costs incurred by all utilities filing under this generic proceeding in accordance with the terms developed as part of this proceeding. The Board may, in its discretion, approve of costs associated with preparation, recovery and restoration efforts that it finds reasonable and prudent at any point during the course of this proceeding.

To the extent any information that is required to be submitted pursuant to this Order is claimed to be confidential, proprietary or raises a security concern, it should be submitted pursuant to the Board’s regulations at N.J.A.C. 14:1-12.1 -12.18.

The Effective Date of this Order is April 1, 2013.

DATED: 3/20/13

BOARD OF PUBLIC UTILITIES
BY:

[Signature]
ROBERT M. HANNA
PRESIDENT

[Signature]
JEANNE M. FOX
COMMISSIONER

[Signature]
JOSEPH L. FIORDALISO
COMMISSIONER

[Signature]
MARY-ANNA HOLDEN
COMMISSIONER

ATTEST:

[Signature]
KRISSIZZO
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.

[Signature]
# IN THE MATTER OF THE BOARD’S ESTABLISHING A GENERIC PROCEEDING TO REVIEW THE PRUDENCY OF COSTS INCURRED BY NJ UTILITY COMPANIES IN RESPONSE TO MAJOR STORM EVENTS IN 2011 AND 2012

**DOCKET NO. AX13030196**

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<tr>
<td>Jerome May</td>
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<tr>
<td>Board of Public Utilities</td>
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<td>44 S. Clinton Avenue, 9th Floor</td>
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<td>P.O. Box 350</td>
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<td>Trenton, NJ 08625-0350</td>
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<tr>
<td>Bethany Rocque-Romaine</td>
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<td>Kristi Izzo, Secretary</td>
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<tr>
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<tr>
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<td>Matthew Weissman, Esq.</td>
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<tr>
<td>General Regulatory Counsel -- Rates</td>
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<tr>
<td>John McAvoy</td>
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<td>C/O John L. Carley, Esq.</td>
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<tr>
<td>Assistant General Counsel</td>
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<tr>
<td>Consolidated Edison Company of NY</td>
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<tr>
<td>4 Irving Place, Room 1815-S</td>
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<td>New York, New York 10003-0987</td>
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6 DOCKET NO. AX13030196
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<td>ACE</td>
<td>Vince Malone</td>
<td>C/O Philip J. Passanante, Esq. Assistant General Counsel</td>
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<td></td>
<td></td>
<td>Atlantic City Electric Company 800 King Street, 5th Floor</td>
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<tr>
<td></td>
<td></td>
<td>Post Office Box 231 Wilmington, DE 19899-0231</td>
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<tr>
<td>JCP&amp;L</td>
<td>Donald Lynch</td>
<td>C/O Gregory Eisenstark, Esq. Morgan, Lewis &amp; Bockius LLP</td>
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<td>89 Headquarters Plaza North Suite 1435 Morristown, NJ 07960</td>
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<tr>
<td>New Jersey Natural Gas</td>
<td>Tracey Thayer, Esq.</td>
<td>Director, Regulatory Affairs Counsel New Jersey Natural Gas</td>
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<td>1415 Wyckoff Road Wall, NJ 07719</td>
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IN THE MATTER OF THE BOARD'S ESTABLISHMENT OF A GENERIC PROCEEDING TO REVIEW COSTS, BENEFITS AND RELIABILITY IMPACTS OF MAJOR STORM EVENT MITIGATION EFFORTS

Establishment of a Proceeding
DOCKET NO. AX13030197

IN THE MATTER OF THE BOARD'S REVIEW OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE ENERGY STRONG PROGRAM

Review of a Petition
DOCKET NOs. EO13020155; GO13020156

Parties of Record:

Ralph LaRossa, Public Service Electric and Gas Co.
Stefanie A. Brand, Esq., Director, Division of Rate Counsel

BY THE BOARD:

The Board of Public Utilities ("Board") is empowered to ensure that regulated public utilities provide safe, adequate and proper service to the citizens of New Jersey. N.J.S.A. 48:2-23. Pursuant to N.J.S.A. 48:2-13, the Board has been vested by the Legislature with the general supervision and regulation of and jurisdiction and control over all public utilities, "so far as may be necessary for the purpose of carrying out the provisions of [Title 48]." The courts of this State have held that the grant of power by the Legislature to the Board is to be read broadly, and that the provisions of the statute governing public utilities are to be construed liberally. See, e.g. In re Public Service Electric and Gas Company, 35 N.J. 358, 371 (1961); Township of Deptford v. Woodbury Terrace Sewerage Corp., 54 N.J. 418, 424 (1969); Bergen County v. Dept' of Public Utilities, 117 N.J. Super. 304 (App. Div. 1971). The Board is also vested with the authority, pursuant to N.J.S.A. 48:2-19, to investigate any public utility, and, pursuant to N.J.S.A. 48:2-16 and 48:2-40, to issue orders to public utilities.

In 2011 and 2012 New Jersey was struck by several extraordinary Major Storm Events, which left millions of New Jersey residents without necessary utility service and caused unprecedented damage to the state's utility infrastructure.

As used in this Order, Major Storm Event means sustained impact on or interruption of utility service:
1. resulting from conditions beyond the control of the utility, which may include, but are not limited to, thunderstorms, tornadoes, hurricanes, heat waves, snow and ice storms; 
2. which affects at least 10 percent of the customers in an operating area; and 
3. due to a utility’s documentable need to allocate field resources to restore service to affected areas when one operating area experiences a Major Storm Event, the Major Storm Event shall be deemed to extend to those other operating areas of that utility which are providing assistance to the affected areas.

The Board retains authority to reexamine the characterization of a Major Storm Event.

RECENT MAJOR STORM EVENTS

Hurricane Irene made landfall at Little Egg Inlet as a Category 1 Hurricane on August 28, 2011. While still out to sea, the storm’s outer bands produced heavy rains and wind that battered New Jersey’s coastal communities. As the storm came ashore, damaging high winds and widespread flooding inundated large portions of the state’s utility infrastructure and caused severe damage to both coastal and interior communities. Statewide approximately 1.9 million customers were affected by outages due to this storm. Power was not fully restored until September 5, 2011.

On October 29, 2011, northern New Jersey was struck with an unseasonal and powerful snowstorm that blanketed the region with record-breaking snowfall. The combination of heavy, wet snow and trees mostly full of foliage triggered extensive infrastructure damage from fallen trees and limbs. The storm caused loss of electrical service to nearly 1 million of the state’s 3.9 million electric customers for up to nine days. Electric service was not fully restored until November 7, 2011.

On June 30 2012, a derecho wind storm left more than 206,000 New Jersey residents without power and caused severe damages to large portions of the energy infrastructure in southern New Jersey. The Federal Emergency Management Agency ("FEMA") attributed 34 deaths across the Midwest and Mid-Atlantic regions to the derecho wind storm. Atlantic City Electric ("ACE") deployed over 1,500 personnel in the ensuing restoration effort.

On October 29, 2013, Superstorm Sandy made landfall near Atlantic City. Sandy’s 90-MPH winds and unprecedented storm surge caused catastrophic damage to dozens of communities across the state. Literally millions of residents were left without power, water, and natural gas service for extended periods of time following the storm.

Just ten days after Superstorm Sandy, on November 7, 2012, a powerful nor’easter brought significant early season snow fall, damaging winds and tidal-surge to New Jersey. Heavy snowfall caused even further damage to New Jersey’s storm-ravaged infrastructure, leaving an additional 167,000 people without power.

As a result of these storms, millions of New Jersey residents were left without electric power, often for extended periods of time. Entire communities were disrupted, and their emergency management capabilities were overextended. Schools and businesses were closed and critical facilities activated emergency contingency plans.
On January 23, 2013, the Board issued an Order addressing five categories of potential improvements to be undertaken by New Jersey's electric distribution companies ("EDCs") in response to Major Storm Events. These categories include: 1) Preparedness Efforts; 2) Communications; 3) Restoration and Response; 4) Post Event; and 5) Underlying Infrastructure Issues. For the purposes of this Order, the Board will address Underlying Infrastructure Issues.

In the January 23 Order, the Board required the EDCs to take specific actions to improve their preparedness in response to extreme weather events. As part of this response, the Board required the EDCs to provide detailed cost benefit analysis associated with a variety of utility infrastructure upgrades. The Board further required the EDCs to "carefully examine their infrastructure and use data available to determine how substations can be better protected from flooding, how vegetation management is impacting electric systems, and how Distribution Automation can be incorporated to improve reliability."

The Board recognizes that there remains a very real threat from future Major Storm Events. Accordingly, the Board finds that it is critical to investigate prudent, cost efficient, and effective opportunities to protect New Jersey's utility infrastructure against damage from future Major Storm Events. While the Board ordered the EDCs to evaluate various storm-related metrics, Superstorm Sandy revealed vulnerabilities in a variety of utility sectors, including electric transmission, and distribution, natural gas distribution, and water delivery infrastructure. Therefore, it is reasonable for the Board to expand its review to the other utilities that serve the citizens of the State.

To properly discharge its statutory responsibilities, as summarized above, and based on the recommendation of Board Staff, as well as comments presented at the public hearings held at various locations across the State, the Board HEREBY FINDS that it is necessary to initiate a proceeding to investigate possible avenues to support and protect New Jersey's utility infrastructure so that it may be better able to withstand the effects of Major Storm Events.

ESTABLISHMENT OF A PROCEEDING TO EVALUATE MAJOR STORM EVENT MITIGATION PROPOSALS

The Board HEREBY ORDERS Staff to open a proceeding to evaluate and review all current and future submissions for storm mitigation efforts to be made by each EDC in compliance with the terms of the January 23 Order under a separate sub-docket numbered proceeding. The Board HEREBY FINDS that it is appropriate to invite all regulated utilities subject to Board jurisdiction, but not parties to the January 23 Order, to submit detailed proposals for infrastructure upgrades designed to protect the State's utility infrastructure from future Major Storm Events, pursuant to the terms and level of detail requested in the January 23 Order. Any proposals filed pursuant to this Order by utilities not subject to the January 23 Order must be submitted by September 3, 2013. The Board has determined that the petition described below, as well as the petitions which may be filed in the future, should be retained by the Board for review and hearing, as authorized by N.J.S.A. 52:14F-8, with a commissioner to be assigned pursuant to N.J.S.A. 48:2-32.

The Board HEREBY ORDERS Staff to investigate whether to retain, and if necessary the

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1 In the Matter of the Board's Review of the Utilities Response to Hurricane Irene, Order Accepting Consultant's Report and Additional Staff Recommendations and Requiring Electric Utilities to Implement Recommendations. BPU Docket No. EO11090543, January 23, 2013 (hereinafter "January 23 Order").
2 January 23 Order at page 56.

DOCKET NOs. AX13030197, EO13020155 and GO13020156
appropriate mechanism to retain an independent expert(s), to aid the Board in reviewing the
efficacy of the measures proposed by the utilities and examining the costs to be potentially
incurred by the New Jersey utilities in association with efforts to protect utility infrastructure from
future Major Storm Events, as well as any potential benefit to be obtained therefrom. The Board
recognizes that maintaining safe, reliable and affordable utility infrastructure is the mandate of
all New Jersey utilities, as is the requirement that rates be just and reasonable. Therefore, the
potential rate impacts associated with decisions made regarding these Major Storm Event
related actions must include an evaluation of the associated benefits of the proposed measures
for protecting the State’s utility infrastructure.

As stated above, the Board recognizes that maintaining safe, adequate, and reliable service is
the mandate of all New Jersey utilities and the minimum standard by which all regulated utilities
must operate. Accordingly, the Board HEREBY ORDERS Staff to require that any entity
retained by the Board to assist in the evaluation of proposed mitigation efforts associated with
Major Storm Events prioritize those proposed mitigation efforts that fall outside of the capital
expenditures normally incurred in the ordinary course of a utility’s business of maintaining its
infrastructure in such a state so as to enable it to provide safe, adequate, and reliable service in
accordance with accepted industry norms.

PETITION BY PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF
THE ENERGY STRONG PROGRAM

On February 20, 2013, Public Service Electric and Gas Company (“PSE&G”) petitioned the
Board for the recovery of costs to bolster its “electric and gas infrastructure to make them less
susceptible to damage from wind, flying debris and water damage in anticipation” of future Major
Storm Events.\(^3\)

PSE&G requested approval of the Energy Strong Petition, the cost of which is to be collected
from ratepayers through the implementation of an “Energy Strong Adjustment Mechanism.”\(^4\)
PSE&G further requests that the Board approve this expenditure and recovery mechanism by
July 1, 2013.

Pursuant to the January 23 Order, the Board required that PSE&G adopt a number of
recommended measures aimed to improve response to future Major Storm Events. The Board
HEREBY FINDS that PSE&G is required to comply with the terms of January 23 Order,
including those terms that address measures to mitigate against future damage to its
infrastructure from Major Storm Events.

The Board HEREBY FINDS that PSE&G’s Energy Strong petition fails to provide the required
detailed estimates of costs, benefits, and/or rate impacts to allow for adequate consideration of
the measures proposed by its petition at this time. The Board HEREBY FINDS that the Energy
Strong petition also fails to adequately distinguish storm hardening and mitigation efforts from
normal operations and maintenance, reliability projects, and programs necessary to maintain
safe, adequate and reliable service within the PSE&G service territory. The Board HEREBY
FINDS that PSE&G must provide all supporting data and analysis necessary to comply with the
January 23 Order, pursuant to the terms and timeframes provided therein. However, the Board

\(^3\) In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Energy
Strong Program at page 1. BPU Docket Nos. GO13020156 and EO13020155 (hereinafter “Energy
Strong”).

\(^4\) Energy Strong at page 4. BPU Docket Nos. GO13020156 and EO13020155.

DOCKET NOs. AX1030197,
EO13020155 and GO13020156
welcomes submission of the requested supplemental filing prior to the deadlines provided in the January 23 Order.

The Board HEREBY DIRECTS Staff to prepare a response to the Energy Strong petition seeking additional information that may be necessary to begin properly evaluating any proposed mitigation measures. Staff shall provide the request to PSE&G no later than ten (10) business days from the effective date of this Order.

The Board further DIRECTS Staff to evaluate any additional Major Storm Event mitigation measures proposed by PSE&G subsequent to receipt of the information requested in the January 23 Order and herein. Any proposed mitigation measures beyond those directed by the January 23 Order shall be evaluated in accordance with the metrics to be developed within this proceeding.

To the extent any information that is required to be submitted pursuant to this Order is claimed to be confidential, proprietary or raises a security concern, it should be submitted pursuant to the Board's regulations at N.J.A.C. 14:1-12.1 - 12.18.

The Effective Date of this Order is April 1, 2013.

DATED: 3/20/13

BOARD OF PUBLIC UTILITIES
BY:

ROBERT M. HANNA
PRESIDENT

JEANNE M. FOX
COMMISSIONER

JOSEPH L. FIORDALISO
COMMISSIONER

MARY ANNA HOLDEN
COMMISSIONER

ATTEST:

KRISTI IZZO
SECRETARY

HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities

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<td>Maria Moran</td>
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<td>45</td>
<td>ALL</td>
<td>The EDCs shall ensure that there are a minimum of three personnel identified, trained and assigned to fill each leadership level position in its emergency / incident response / storm restoration organization. The EDCs shall submit to Staff a list of the leadership positions and three personnel identified for each position.</td>
<td>Restoration and Response</td>
<td>Command and Control</td>
<td>365 Days</td>
<td>1-Feb-14</td>
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<td>46</td>
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<td>The EDCs shall implement a cell phone application that customers can use to report outages and receive system outage information.</td>
<td>Restoration and Response</td>
<td>Responder Systems, Tools and Job Aids</td>
<td>365 Days</td>
<td>1-Feb-14</td>
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<td>The EDCs and Staff shall establish a work group to develop plans for a tracking system for distribution system outages related to trees and vegetation. This program shall track information such as the outage causation, proximity of the tree/vegetation to electrical facilities, last trimming cycle of the circuit that experienced the outage, location of tree/vegetation within or outside of the right-of-way (ROW) or easement, and any other pertinent factors, including storm event, local cutting, wind, etc. This tracking system shall be maintained by the respective EDC and be available to Staff upon request.</td>
<td>Underlying Infrastructure Issues</td>
<td>Vegetation Management</td>
<td>60 Days</td>
<td>2-Apr-13</td>
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<td>62</td>
<td>ALL</td>
<td>BPU-62) The EDCs shall review their vegetation outage data and correlate this information into an analysis of their impacts to the system reliability. The EDCs shall prepare and submit to Staff an explanation of this analysis showing any perceived benefits or concerns with the impact of the programs to the health of the system.</td>
<td>Underlying Infrastructure Issues</td>
<td>Vegetation Management</td>
<td>60 Days</td>
<td>2-Apr-13</td>
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<td>1</td>
<td>ACE</td>
<td>ACE shall modify its organizational charts to reflect position titles instead of names.</td>
<td>Preparedness Efforts</td>
<td>Planning</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>1</td>
<td>JCPL</td>
<td>JCP&amp;L shall include the Construction Restoration Lead’s plan and any individually developed job aids or checklists in its emergency plan.</td>
<td>Preparedness Efforts</td>
<td>Planning</td>
<td>90 Days</td>
<td>2-May-13</td>
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<td>8</td>
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<td>The EDCs shall develop a centralized repository of training records for all positions involved with storm restoration and send notice</td>
<td>Preparedness Efforts</td>
<td>Training</td>
<td>90 Days</td>
<td>2-May-13</td>
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<td>3</td>
<td>JCPL</td>
<td>JCP&amp;L shall develop and submit to Staff a procedure to track on the job training participation.</td>
<td>Preparedness Efforts</td>
<td>Training</td>
<td>90 Days</td>
<td>2-May-13</td>
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<td>12</td>
<td>ALL</td>
<td>The EDCs shall submit to Staff standard pre-storm customer messaging revised to emphasize to customers to prepare for the possibility of long duration outages, and provide safety advice and sources of emergency preparedness information.</td>
<td>Communications</td>
<td>Pre-Event</td>
<td>90 Days</td>
<td>2-May-13</td>
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<td>13</td>
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<td>The EDCs shall submit to Staff revised procedures for maintaining logs of all media activity for use in its post event analysis.</td>
<td>Communications</td>
<td>Pre-Event</td>
<td>90 Days</td>
<td>2-May-13</td>
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<td>14</td>
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<td>The EDCs shall revise and submit to Staff their IVR and Voice Response Unit (VRU) messages to ensure they are in plain language that is easily understandable to the vast majority of their customers. For Major Events, with anticipated outages of three (3) or more days, the EDCs Live Agent and IVR messages regarding Estimated Times of Restoration (ETR) shall contain information and resources to help customers plan their actions to deal with an extended outage.</td>
<td>Communications</td>
<td>Customer Service/Call Center</td>
<td>90 Days</td>
<td>2-May-13</td>
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<td>17</td>
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<td>The EDCs shall develop and submit to Staff messaging scripts that provide easily understood and comprehensive advice to customers for planning their actions to deal with outages and for staying safe.</td>
<td>Communications</td>
<td>External Communications</td>
<td>90 Days</td>
<td>2-May-13</td>
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<td>3</td>
<td>RECO</td>
<td>RECO shall implement all of the improvements detailed in its revised restoration plan and submit to Staff a list of the improvements implemented.</td>
<td>Communications</td>
<td>External Communications</td>
<td>90 Days</td>
<td>2-May-13</td>
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<td>4</td>
<td>RECO</td>
<td>RECO shall submit to Staff documentation demonstrating that it has sufficient space for its communications team.</td>
<td>Communications</td>
<td>External Communications</td>
<td>90 Days</td>
<td>2-May-13</td>
<td></td>
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<tr>
<td>ALL</td>
<td>The EDCs shall develop and submit to Staff a plan for ensuring they have sufficient message writers and government affairs personnel in a Major Event. The plan shall include procedures to inform elected officials about the restoration process.</td>
<td>Communications</td>
<td>External Communications</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>ALL</td>
<td>The EDCs shall develop and submit to Staff a procedure to log and keep samples of internal communications to assist in developing lessons learned.</td>
<td>Communications</td>
<td>Internal Communications</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>JCPL</td>
<td>JCP&amp;L shall develop and submit to Staff criteria for the activation of its emergency response plan, including clearly defined procedures for all functions. In its submission to Staff, JCP&amp;L shall analyze any risks associated with the plan, including any risks inherent in requiring the movement of personnel between affiliates in severe weather. JCP&amp;L shall also propose a plan to manage these risks.</td>
<td>Restoration and Response</td>
<td>Activation</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>PSEG</td>
<td>PSE&amp;G shall develop and submit to Staff a plan to mobilize additional skilled personnel to support a major storm activation, including identifying by job title the employees that would be available to support the restoration efforts for a significant event.</td>
<td>Restoration and Response</td>
<td>Activation</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>ACE</td>
<td>ACE shall submit to Staff a new section to its Plan to describe how mutual assistance crews will be allocated among affiliated companies (ACE, Delmarva, and Pepco) when simultaneous large-scale events occur in multiple service territories.</td>
<td>Restoration and Response</td>
<td>Mutual Assistance</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>RECO</td>
<td>RECO shall submit to Staff a new section to its Plan to describe how mutual assistance crews will be allocated among affiliated companies (ConEdison and Orange &amp; Rockland) when simultaneous large-scale events occur in multiple service territories.</td>
<td>Restoration and Response</td>
<td>Mutual Assistance</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>PSEG</td>
<td>PSE&amp;G shall, as of the date of this Order, for all future events report the number of personnel, instead of crews, when reporting the number of personnel that assisted during weather events.</td>
<td>Restoration and Response</td>
<td>Mutual Assistance</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>PSEG</td>
<td>PSE&amp;G shall develop and submit to Staff a deployment plan that effectively uses drivers and damage assessors to conduct damage assessment.</td>
<td>Restoration and Response</td>
<td>Damage Assessment</td>
<td>90 Days</td>
<td>2-May-13</td>
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<tr>
<td>JCPL</td>
<td>JCP&amp;L shall develop and submit to Staff a standardized process for the calculation of ETRs at multiple levels of Restoration and Response</td>
<td>Estimated Restoration Times(ETR)</td>
<td>90 Days</td>
<td>2-May-13</td>
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granularity, which shall be documented in its E-plan.

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<tr>
<td>14</td>
<td>JCPL</td>
<td>JCP&amp;L shall centralize the responsibility for the ETR process into a single function and submit details of this program to Staff.</td>
<td>Restoration and Response</td>
</tr>
<tr>
<td>47</td>
<td>ALL</td>
<td>The EDCs shall develop and submit to Staff ice and water provisioning plans for Major Events, which shall provide for specific implementation trigger points, geographic criteria for supply points, and duration of supply distribution. The plans may include affiliations with existing retail establishments and distribution assistance to be provided by local, county and state emergency management officials. The EDCs shall provide Staff with a copy of the plan adopted to engage media and other communications methods to advise customers of the availability and location of these items.</td>
<td>Restoration and Response</td>
</tr>
<tr>
<td>51</td>
<td>ALL</td>
<td>The EDCs shall implement and submit to Staff documentation of a process by which, during a Major Event, EDCs shall report to Staff at least once per day (after the first 24 hours), or as requested, the estimated man-hours required to restore all remaining affected customers.</td>
<td>Post Event</td>
</tr>
<tr>
<td>52</td>
<td>ALL</td>
<td>BPU-52) The EDCs shall submit to Staff a list of Regional Mutual Assistance Groups (RMAG) and/or utilities they have agreements with to share restoration experiences.</td>
<td>Post Event</td>
</tr>
<tr>
<td>53</td>
<td>ALL</td>
<td>The EDCs shall implement a process by which, following a Major Event, they shall solicit input regarding their performance from affected external stakeholders, via letter, email, conference call, personal contact or by meeting, and document the feedback provided. This documented input shall be available for review by Staff upon request.</td>
<td>Post Event</td>
</tr>
<tr>
<td>54</td>
<td>ALL</td>
<td>The EDCs shall implement the use of logs to track activities and document decisions by storm team leadership members, which shall be available for review by Staff upon request.</td>
<td>Post Event</td>
</tr>
<tr>
<td>55</td>
<td>PSEG</td>
<td>PSE&amp;G shall complete its flood mitigation study and submit for Board consideration a proposal for implementation of the recommended mitigation measures, which shall include a cost benefit analysis and a work plan.</td>
<td>Underlying Infrastructure Issues</td>
</tr>
</tbody>
</table>
Each EDC shall file a Smart Grid - Distribution Automation Plan (SG-DAP) filing. The Smart Grid - Distribution Automation Plan shall include the development and implementation of feeder and substation automation as part of an overall Distribution Management System (DMS) and Outage Management System (OMS). The SG-DAP shall, including but not be limited to the following: Automatic circuit reclosures (ACR), automation sectionalizing and restoration (ASR), advanced voltage control, VARs control, network protection/monitoring/controls, remote terminal units, remote fault detection, smart relays, equipment health sensors, outage detection devices and smart meters. The Smart Grid – Distribution Automation Plan Filing shall include the timeframe for the development of each component and the overall plan, as well as the costs and benefits of each individual component and the entire plan to the EDC and the ratepayer. The Smart Grid – Distribution Automation shall be developed with the goal to implement a more resilient and “self-healing” distribution grid and with the objective to improve the distribution system reliability and optimize the distribution grid operation overall with a specific focus during and after a storm events such as Irene.

*PLEASE NOTE THAT THE EFFECTIVE DATE OF THE CORRESPONDING BOARD ORDER IS FEBRUARY 1, 2013.*
<table>
<thead>
<tr>
<th>#</th>
<th>EDC</th>
<th>ACTION</th>
<th>CATEGORY</th>
<th>SUBCATEGORY</th>
<th>ALLOTED TIME</th>
<th>DEADLINE</th>
<th>DATE RECEIVED</th>
<th>EDC CONTACT PERSON</th>
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</thead>
<tbody>
<tr>
<td>2</td>
<td>ALL</td>
<td>The EDCs shall use an ICS structure in their emergency organizations.</td>
<td>Preparedness Efforts</td>
<td>Organizational Structure, Roles and</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td>The EDCs shall update their E-Plans and OMS Manuals to reflect the use</td>
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<td>Responsibilities</td>
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<td>of an Incident Command System (ICS) structure in their emergency</td>
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<td>organizations. No individual shall assume more than one role in the</td>
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<td>ICS during a Major Event. The EDCs shall submit to Staff a report</td>
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<td>detailing the ICS implementation or modifications.</td>
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<td>3</td>
<td>ALL</td>
<td>The EDCs shall establish an Emergency Management/Preparedness role as</td>
<td>Preparedness Efforts</td>
<td>Organizational Structure, Roles and</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td></td>
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<td>a stand-alone function within their organizational structures with</td>
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<td>Responsibilities</td>
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<td>the requisite authority to set and execute preparedness goals. The</td>
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<td>EDCs shall provide to Staff documentation of the implementation of</td>
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<td>the Emergency Management/Preparedness role, including, but not</td>
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<td>limited, to the date hired, resume, reporting relationship, and how</td>
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<td>the individual will be integrated into the company.</td>
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<td>4</td>
<td>ALL</td>
<td>The EDCs shall identify and train sufficient second role personnel to</td>
<td>Preparedness Efforts</td>
<td>Organizational Structure, Roles and</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td>meet emergency staffing needs, pre-assign appropriate personnel and</td>
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<td>Responsibilities</td>
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<td>provide training in advance of a predicted Major Event. The EDCs</td>
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<td>shall provide documentation to Staff on the number of staff trained</td>
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<td>and the training schedule.</td>
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<td>5</td>
<td>ALL</td>
<td>The EDCs shall update and submit to Staff their emergency plans to</td>
<td>Preparedness Efforts</td>
<td>Planning</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td>reflect the elevated response required for a large scale restoration</td>
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<td>event; ensure that the roles and responsibilities as defined in their</td>
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<td>emergency plans are followed in actual practice; provide for the</td>
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<td>annual review, updating and distribution of its emergency plans; and</td>
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<td>provide to Staff documentation of these changes.</td>
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<td>7</td>
<td>ALL</td>
<td>The EDCs shall develop and submit to Staff plans to implement an</td>
<td>Preparedness Efforts</td>
<td>Exercises/Drills</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td>annual exercise in which their personnel will staff the County and</td>
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<td>Local Emergency Operations Centers (EOCs) in their service territories</td>
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<td>with the goal of creating familiarity with the facilities, developing</td>
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<td>relationships with Emergency Management Officials and verifying the</td>
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<td>functionality of all field equipment. The EDCs shall include a target</td>
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<td>date for the first exercise in these implementation plans and notify</td>
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<td>Staff at least 30 days before each annual exercise is scheduled to</td>
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<td>take place.</td>
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<td>2</td>
<td>JCPL</td>
<td>JCP&amp;L shall develop and submit to Staff policies for conducting an</td>
<td>Preparedness Efforts</td>
<td>Exercises/Drills</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td>annual storm restoration exercise that will include participation of</td>
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<td>personnel from all functional units/departments that play a role in</td>
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<td>storm restoration and external agencies; conducting an internal annual</td>
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</table>

2  JCPL  JCP&L shall develop and submit to Staff policies for conducting an annual storm restoration exercise that will include participation of personnel from all functional units/departments that play a role in storm restoration and external agencies; conducting an internal annual storm
<table>
<thead>
<tr>
<th></th>
<th>EDC</th>
<th>Description</th>
<th>Effort Area</th>
<th>Timeframe</th>
<th>Start Date</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>PSEG</td>
<td>PSE&amp;G shall develop and submit to Staff policies for conducting an annual storm restoration exercise that will include larger scale events in its annual exercises and will include personnel from all functional units/ departments that play a role in storm restoration; and for developing a post exercise report and improvement plan following each exercise.</td>
<td>Preparedness Efforts</td>
<td>Exercises/Drills</td>
<td>120 Days</td>
</tr>
<tr>
<td>2</td>
<td>PSEG</td>
<td>PSE&amp;G shall revise its OMS Manual to include policies and procedures for the collection, analysis and dissemination of weather information, and provide Staff with the revised manual.</td>
<td>Preparedness Efforts</td>
<td>Weather Monitoring/Forecasting</td>
<td>120 Days</td>
</tr>
<tr>
<td>4</td>
<td>JCPL</td>
<td>JCP&amp;L shall implement the recommendations contained in its Storm Restoration Communications Implementation Plan. JCP&amp;L shall launch its storm website and notify its customers of its activation two (2) days prior to an expected major event storm or immediately upon the arrival of an unexpected major event storm. JCP&amp;L shall update its Interactive Voice Response (IVR) messages with storm warning and preparedness information two (2) days prior to an expected major event storm or immediately upon the arrival of an unexpected major event storm. JCP&amp;L shall submit to Staff written procedures reflecting these changes and a copy of the finalized Storm Restoration Communications Implementation Plan.</td>
<td>Communications</td>
<td>Pre-Event Communications</td>
<td>120 Days</td>
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<tr>
<td>19</td>
<td>ALL</td>
<td>The EDCs shall modify their IVR so that multiple customer telephone numbers may be accepted.</td>
<td>Communications</td>
<td>External Communications</td>
<td>120 Days</td>
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<tr>
<td>20</td>
<td>ALL</td>
<td>The EDCs shall provide additional methods for customers to report and check on the status of an individual outage using mobile devices.</td>
<td>Communications</td>
<td>External Communications</td>
<td>120 Days</td>
</tr>
<tr>
<td>21</td>
<td>ALL</td>
<td>The EDCs shall provide Staff with a web portal to view additional details related to outages and provide a mechanism to automatically notify Staff via email or text message when certain outage thresholds are reached.</td>
<td>Communications</td>
<td>External Communications</td>
<td>120 Days</td>
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<tr>
<td>22</td>
<td>ALL</td>
<td>The EDCs shall update their websites as follows, and notify Staff that the following changes have been implemented:</td>
<td>External Communications</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<tr>
<td>23 ALL BPU-23</td>
<td>The EDCs shall establish and maintain webpages describing storm safety and preparedness information, and general restoration processes and procedures.</td>
<td>Communications</td>
<td>External Communications</td>
<td>120 Days</td>
<td>1-Jun-13</td>
</tr>
<tr>
<td>24 ALL BPU-24</td>
<td>The EDCs shall establish and maintain, for each municipality in their respective service territories, a separate webpage with the following information:</td>
<td>Communications</td>
<td>External Communications</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<tr>
<td>25 ALL</td>
<td>During outages, each municipality’s webpage shall be updated with the following information as the information becomes available:</td>
<td>Communications</td>
<td>External Communications</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td>26 ALL</td>
<td>During outages, the EDCs shall establish and maintain county-by-county information as follows:</td>
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<td>120 Days</td>
<td>1-Jun-13</td>
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<tr>
<td>35 ALL</td>
<td>The EDCs shall develop and submit to Staff a plan to acquire additional line personnel in the event of a wide-spread natural disaster that stresses the RMAG system.</td>
<td>Restoration and Response</td>
<td>Mutual Assistance</td>
<td>120 Days</td>
<td>1-Jun-13</td>
</tr>
<tr>
<td>8 JCPL OMS Manual</td>
<td>JCPL shall submit to Staff documentation that FirstEnergy has developed a process regarding the provision of mutual assistance to JCPL during major events, including an appendix in FirstEnergy E-Plan addressing the following:</td>
<td>Restoration and Response</td>
<td>Mutual Assistance</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td></td>
<td>PSE&amp;G shall revise the mutual assistance section in its OMS Manual to include a description of who is responsible for the following: estimating resource needs, participating in Regional Mutual Assistance Group (RMAG) conference calls, and making the decision to send or obtain mutual assistance. PSE&amp;G shall participate in RMAG calls even when its mutual assistance needs are not being met by the RMAG. The specific location of the revision shall be noted when the revised OMS Manual is submitted.</td>
<td>Restoration and Response</td>
<td>Mutual Assistance</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<td></td>
<td>JCP&amp;L shall ensure that the approved quarantine process of circuit restoration is integrated into the E-Plan and that appropriate personnel are trained. A report detailing the implementation of this recommendation shall be submitted to Staff.</td>
<td>Restoration and Response</td>
<td>Crew/Work Management/Workforce Levels</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<tr>
<td>7 PSEG</td>
<td>PSE&amp;G shall define the process of circuit-based restoration and the escalation process in its OMS Manual and specifically identify the location of the relevant language when submitting the revised copy of the Manual to Staff.</td>
<td>Restoration and Response</td>
<td>Crew/Work Management/Workforce Levels</td>
<td>120 Days</td>
<td>1-Jun-13</td>
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<tr>
<td>10 JCPL</td>
<td>JCP&amp;L shall develop and submit to Staff a rapid damage assessment process to be used during Major Events, which shall include a detailed description of the prioritization of areas to be assessed, the method for assigning personnel, the timeframe for personnel to report back with their findings, as well as any other information requested by Board Staff.</td>
<td>Restoration and Response</td>
<td>Damage Assessment</td>
<td>120 Days</td>
<td>1-Jun-13</td>
</tr>
<tr>
<td>42</td>
<td>ALL</td>
<td>The EDCs shall make available to customers a global ETR 24 hours after a major event outage. Beginning 48 hours after a major event outage, the EDCs shall make available to municipal officials daily updates concerning the number of customers out in their towns and the estimated number of customers that will be restored each day until restoration is completed.</td>
<td>Restoration and Response</td>
<td>Estimated Restoration Times (ETR)</td>
<td>120 Days</td>
</tr>
<tr>
<td>43</td>
<td>ALL</td>
<td>The EDCs shall, at a minimum, give priority restoration to customers who have been identified to the companies as those with special needs as defined in N.J.A.C. 14:3-3A.4(d) once the EDCs have reached the lateral/branch circuit and/or individual customer point in the process, while still giving consideration to restoring large groups of customers. Communications to those identified as special needs customers will include, at a minimum, a pre-event call to warn of impending possible outages and an intra-event call to provide an ETR. The EDCs shall submit to Staff details of this procedure and documentation of its implementation.</td>
<td>Restoration and Response</td>
<td>Estimated Restoration Times (ETR)</td>
<td>120 Days</td>
</tr>
<tr>
<td>15</td>
<td>JCPL</td>
<td>JCP&amp;L shall develop and submit to Staff staffing contingency plans to deal with a Major Event during which FirstEnergy corporate support is limited.</td>
<td>Restoration and Response</td>
<td>Command and Control</td>
<td>120 Days</td>
</tr>
<tr>
<td>9</td>
<td>PSEG</td>
<td>PSE&amp;G shall follow the ICS organizational model endorsed in its OMS Manual, revise its OMS Manual to define a clear role for the executives in accordance with ICS principles. The revisions shall be included in the OMS manual, and provided to Staff in a separate report as well for easier identification.</td>
<td>Restoration and Response</td>
<td>Command and Control</td>
<td>120 Days</td>
</tr>
<tr>
<td>49</td>
<td>ALL</td>
<td>The EDCs shall develop and submit a clearly defined section in their plans outlining the follow-up “temporary repairs” work processes and responsibilities, including post storm patrolling and inspection.</td>
<td>Restoration and Response</td>
<td>Follow up Work</td>
<td>120 Days</td>
</tr>
<tr>
<td>50</td>
<td>ALL</td>
<td>The EDCs shall develop and submit to Staff a storm quality assessment process to track the locations of all temporary repairs and the date each temporary repair was made permanent.</td>
<td>Restoration and Response</td>
<td>Follow up Work</td>
<td>120 Days</td>
</tr>
<tr>
<td>55</td>
<td>ALL</td>
<td>The EDCs shall each identify one responsible party, who will review all ‘lessons learned,’ meet with the submitting departments, finalize action items, and assign responsibility for the action items, track action item completion and report progress to leadership. The EDCs shall submit to Staff the name of the responsible party and the reporting structure he or she will use.</td>
<td>Post Event</td>
<td>Post Event Processes</td>
<td>120 Days</td>
</tr>
<tr>
<td>18</td>
<td>JCPL</td>
<td>JCP&amp;L shall implement, and submit to Staff documentation of, a process to ensure timely completion and final approval of process improvement items noted during post storm</td>
<td>Post Event</td>
<td>Post Event Processes</td>
<td>120 Days</td>
</tr>
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<tr>
<td>8</td>
<td>RECO</td>
<td>RECO’s Emergency Management Department will review all 'lessons learned,' track the required improvements, and ensure their final, appropriate and timely completion, report progress to leadership, and submit to Staff documentation demonstrating implementation.</td>
<td>Post Event</td>
<td>Post Event Processes</td>
<td>120 Days</td>
</tr>
<tr>
<td>11</td>
<td>PSEG</td>
<td>PSE&amp;G should develop and submit to Staff documentation of a process to perform 'lessons learned' after each Major Event to find and reward innovative actions, understand training requirements, correct errors or omissions in its OMS Manual, foster a culture of continuous improvement, and establish a timeframe when these post event reviews will be completed.</td>
<td>Post Event</td>
<td>Post Event Processes</td>
<td>120 Days</td>
</tr>
<tr>
<td>57</td>
<td>ALL</td>
<td>The EDCs shall develop and submit to Staff specific substation flooding preparedness plans which detail mitigation steps to be taken and monitoring prior to and during major storm events.</td>
<td>Underlying Infrastructure Issues</td>
<td>Substation Flooding</td>
<td>120 Days</td>
</tr>
<tr>
<td>58</td>
<td>ALL</td>
<td>The EDCs shall prepare a report, to be submitted to the Board that prioritizes the EDCs’ proposed responses to various levels of potential flooding at each substation and switching station at risk of flooding (up to and including the levels of water encroachment that occurred in both Hurricane Irene and Superstorm Sandy).</td>
<td>Underlying Infrastructure Issues</td>
<td>Substation Flooding</td>
<td>120 Days</td>
</tr>
</tbody>
</table>

*PLEASE NOTE THAT THE EFFECTIVE DATE OF THE CORRESPONDING ORDER IS FEBRUARY 1, 2013.*
<table>
<thead>
<tr>
<th>#</th>
<th>EDC</th>
<th>ACTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>ALL</td>
<td>All EDCs shall revise, and submit to Staff, their emergency plans to manage the restoration of service to a minimum of 75% of their customers, and include descriptions of emergency organization; emergency classifications; annual training and exercise program; on-going readiness initiatives; pre-event preparatory measures; procedures for mobilizing personnel, materials and equipment; communications procedures; process for acquiring external resources; process for acquiring internal support services; and linkages to corporate plans, if applicable.</td>
</tr>
<tr>
<td>10</td>
<td>ALL</td>
<td>The EDCs shall establish specific training requirements for all positions involved with storm restoration and provide the training schedule to Staff.</td>
</tr>
<tr>
<td>11</td>
<td>ALL</td>
<td>The EDCs shall revise their training programs to include the training of personnel on cross-functional interdependencies within the storm restoration organization and provide the revised procedures to Staff.</td>
</tr>
<tr>
<td>15</td>
<td>ALL</td>
<td>The EDCs shall submit documentation to Staff demonstrating that they have established call center performance standards for Average Speed of Answer (ASA) and Abandonment Rate (AR) during major outage events; adopted procedures to ensure call center staff meets ASA and AR standards during a major outage event; and developed IVR/VRU messages that contain helpful and accurate information and which will be updated at least daily during an extended outage.</td>
</tr>
<tr>
<td>2</td>
<td>RECO</td>
<td>RECO shall conduct a study that examines the adequacy of its resources and its affiliates’ resources if a major event simultaneously affects both of their service territories; implement its process enhancements; and submit to Staff the results of the resource adequacy study and documentation of implementation of process enhancements.</td>
</tr>
<tr>
<td>27</td>
<td>ALL</td>
<td>The EDCs shall submit to Staff documentation that they are using social media as part of their communications with the public during Major Events.</td>
</tr>
<tr>
<td>28</td>
<td>ALL</td>
<td>EDCs shall submit to Staff documentation that they are allowing customers to report outages by telephone to their accounts via multiple phone numbers, and notifying customers of the availability of this service.</td>
</tr>
<tr>
<td>29</td>
<td>ALL</td>
<td>The EDCs shall submit to Staff documentation that they have designated a company representative with direct responsibility for system operations and restoration to communicate directly with Staff.</td>
</tr>
<tr>
<td>3</td>
<td>PSEG</td>
<td>PSE&amp;G shall identify and train sufficient second role personnel as backup representatives for staffing OEMs and submit the names and positions of the employees to the Staff.</td>
</tr>
<tr>
<td>31</td>
<td>ALL</td>
<td>The EDCs shall develop and submit to Staff a Storm Damage and Outage Prediction Model. This model may be computerized, but must provide for input of all factors required to estimate storm damage. For each major storm, the EDCs shall incorporate the prediction model in the estimation of the resources needed to respond to the event. This information shall be submitted to Staff 1 day prior to a predicted storm’s arrival.</td>
</tr>
<tr>
<td>36</td>
<td>ALL</td>
<td>The EDCs shall submit to Staff a detailed staffing review that explains any decreases, in the last 5 years, in headcount and the impact on the company’s ability to provide adequate resources for restoration purposes.</td>
</tr>
</tbody>
</table>

**CATEGORY**: Preparedness Efforts

**SUBCATEGORY**: Exercises/Drills

**ALLOTED TIME**: 180 days

**DEADLINE**: 31-Jul-13

**MISC. /NOTES**
<table>
<thead>
<tr>
<th>#</th>
<th>ALL</th>
<th>The EDCs shall develop and submit to Staff a common damage &quot;glossary&quot; for reporting damage to the BPU during and after events.</th>
<th>Restoration and Response</th>
<th>Crew/Work Management/Workforce Levels</th>
<th>180 Days</th>
<th>31-Jul-13</th>
</tr>
</thead>
<tbody>
<tr>
<td>38</td>
<td>ALL</td>
<td>The EDCs shall develop a procedure to track crew locations throughout the restoration process and report this information to the BPU Staff as requested. In addition, if requested by Staff, the EDCs shall report crew locations at the municipal level.</td>
<td>Restoration and Response</td>
<td>Crew/Work Management/Workforce Levels</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>39</td>
<td>ALL</td>
<td>The EDCs shall participate with other key stakeholders in a debris management initiative organized by the Reliability and Security Staff to establish a structured process to determine roadway access prioritization.</td>
<td>Restoration and Response</td>
<td>Crew/Work Management/Workforce Levels</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>40</td>
<td>ALL</td>
<td>The EDCs shall each develop and conduct a customer education program regarding field restoration work processes, and submit to Staff a report detailing this program.</td>
<td>Restoration and Response</td>
<td>Crew/Work Management/Workforce Levels</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>11</td>
<td>JCPL</td>
<td>JCP&amp;L shall ensure that it has sufficient trained personnel to conduct the damage assessment process in parallel with the hazard process. JCP&amp;L shall submit to Staff the details of these programs.</td>
<td>Restoration and Response</td>
<td>Damage Assessment</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>12</td>
<td>JCPL</td>
<td>JCP&amp;L shall establish a dedicated planning function to analyze information coming in from the damage assessments. JCP&amp;L shall submit to Staff details of this process.</td>
<td>Restoration and Response</td>
<td>Damage Assessment</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>41</td>
<td>ALL</td>
<td>The EDCs shall submit to the Board for review and approval a plan for the implementation of technology solutions to enable more efficient reporting and/or processing of damage assessment information.</td>
<td>Restoration and Response</td>
<td>Damage Assessment</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>44</td>
<td>ALL</td>
<td>Each EDC shall conduct and submit to Staff a study of the accuracy of its ETRs during Major Events during the last three years.</td>
<td>Restoration and Response</td>
<td>Estimated Restoration Times(ETR)</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>16</td>
<td>JCPL</td>
<td>JCP&amp;L shall implement the use of Mobile Data Terminals to relay data to and from the field.</td>
<td>Restoration and Response</td>
<td>Responder Systems, Tools and Job Aids</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>48</td>
<td>ALL</td>
<td>The EDCs shall predetermine Staging Areas sufficient to support restoration from an outage equal to 75% of total customers including location specific layouts. The EDCs shall have any necessary contractual arrangements in place for the use of the predetermined Staging Areas to resolve issues such as liability, access, security and existing support services at the site prior to a Major Event. The EDCs shall submit to Staff a report detailing this program.</td>
<td>Restoration and Response</td>
<td>Logistics and Field Support</td>
<td>180 Days</td>
<td>30-Jul-13</td>
</tr>
<tr>
<td>7</td>
<td>RECO</td>
<td>JCP&amp;L and RECO shall assume the responsibility for lodging for foreign contractors and submit an implementation plan to Staff.</td>
<td>Restoration and Response</td>
<td>Logistics and Field Support</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>10</td>
<td>PSEG</td>
<td>PSE&amp;G shall develop, and submit to Staff documentation of a standard Staging Area resource complement to ensure that operations can be managed effectively if adverse weather conditions occur during an extended restoration. PSE&amp;G shall update its OMS Manual to include a detailed Staging Area plan.</td>
<td>Restoration and Response</td>
<td>Logistics and Field Support</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>59</td>
<td>ALL</td>
<td>The EDCs shall submit to the Staff an analysis of the current 100 year flood plan data for their respective areas of operation, an evaluation of the need to design for higher flood elevation in future substation installations within flood zone areas or other vulnerable areas, and any other recommendations regarding design improvements, including a cost-benefit analysis and a work plan.</td>
<td>Underlying Infrastructure Issues</td>
<td>Substation Flooding</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
</tbody>
</table>
The EDCs shall coordinate with municipal and facility stakeholders (e.g., local or county drainage, dam and water facilities) whose infrastructure or operations can impact substations in vulnerable flood areas. These meetings shall be considered as working groups for the stakeholders to discuss past events, operational and logistical concerns, and communications. The minutes of each meeting shall be submitted to the Staff within 30 days after that meeting.

<table>
<thead>
<tr>
<th>#</th>
<th>Owner</th>
<th>Action</th>
<th>Underlying Infrastructure Issues</th>
<th>Substation Flooding</th>
<th>180 Days</th>
<th>31-Jul-13</th>
</tr>
</thead>
<tbody>
<tr>
<td>60</td>
<td>ALL</td>
<td>The EDCs shall coordinate with municipal and facility stakeholders (e.g., local or county drainage, dam and water facilities) whose infrastructure or operations can impact substations in vulnerable flood areas. These meetings shall be considered as working groups for the stakeholders to discuss past events, operational and logistical concerns, and communications. The minutes of each meeting shall be submitted to the Staff within 30 days after that meeting.</td>
<td>Underlying Infrastructure Issues</td>
<td>Substation Flooding</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
<tr>
<td>19</td>
<td>JCP&amp;L</td>
<td>JCP&amp;L shall develop and submit to Staff a plan to document its &quot;institutional knowledge&quot; of the vegetation impacts and mitigation on its systems with the goal of making this information available to all personnel during Major Events.</td>
<td>Underlying Infrastructure Issues</td>
<td>Vegetation Management</td>
<td>180 Days</td>
<td>31-Jul-13</td>
</tr>
</tbody>
</table>

*PLEASE NOTE THAT THE EFFECTIVE DATE OF THE CORRESPONDING ORDER IS FEBRUARY 1, 2013.*
Combined Heat and Power (CHP) Long Term Financing Incentive Mechanism

A “smart” Portfolio Standard

Goal: To develop a long term secure and stable funding/financing source to implement the 2011 Energy Master Plan CHP target of 1500 MW that includes both storm response CHP and dual economic and environmental benefit CHP.

Objectives:
- Develop CHP as part of the State’s long term strategies for economic development.
- Develop a near term CHP storm response program for critical public facilities.
- Develop a non-lapsable funding source
- No new certificate trading programs

The specifics of a long term financing mechanism would be established in detail through a stakeholder process the following is an initial straw for initial discussion purposes only.

As set forth at NJSA 48:3-87 g and h, the Board currently has the statutory authority to adopt, pursuant to the Administrative Procedures Act, an energy efficiency portfolio standard (EEPS) includes both an electric energy efficiency portfolio standard (EEEPS) and a gas portfolio energy efficiency standard (GEEPS). As defined in the statute, the EEEPS and the GEEPS targets may be up to 20% below the electric or gas usage projected by the Board in 2020 without the EEEPS or the GEEPS. As provided in the statutes, the EEEPS would be set on the electric public utility (electric distribution companies EDC) to establish energy efficiency (EE) measures to reduce the electric usage. The GEEPS would be set on the gas public utilities (gas distribution companies GDC) to establish EE measures to reduce the gas usage for heating.

An EEPS, as defined in the statutes, means a requirement to procure a specific amount of EE or demand side management resources as a means of reducing energy usage and demand by customers.

CHP is an energy efficiency measure. CHP, in addition to providing onsite generation of electricity, saves electricity through more efficient cooling equipment and processes; and saves gas through more efficient heating/cooling equipment and processes. The CHP can be developed as an EEEPS or a GEEPS or both as a CHP PS. The CHP PS simply takes the EMP goal for CHP and establishes it as a specific regulatory requirement.
The CHP PS would differ significantly from the current renewable energy portfolio standard (RPS). By directing the CHP PS to the utilities as set forth in the statutes to procure the PS obligation eliminates the need for a number of the provisions in the current RPS rules such as the alternate compliance payment (ACP) structure and penalties. The ACP structure and penalties are required because the current solar, Class I and Class II RPS is an obligation on the electric suppliers and basis generator providers and is a market-based structure.

The ACP is not a penalty. The ACP provides another means of compliance in a competitive market requirement structure. The ACP acts as a safety value in undersupplied market and is also available to prevent market manipulation by the renewable energy customer generators, marketers or aggregators. The Board, in terms of the EEPS, would directly regulate the utilities. These other mechanisms in the RPS can be built directly into the regulatory oversight of the utilities. The Board does not directly economically regulate the suppliers and providers, which is the reason for the ACP and penalties for non-compliance.

By directly regulating the electric and gas utilities under the EEPS provisions there would be no need for any additional incentives or penalties for the utilities to perform as required by the Board. The CHP PS provisions would include the ability of the utilities to recover their cost as currently provided for in the statutes and regulations, but eliminates the other provisions as required in a competitive RPS marketplace. The structure for recovery would be built into the overall EEPS regulatory structure.

As similar to the RPS the CHP PS would be set statewide annually as a percentage of the CHP EMP goal through energy year 2021. This annual statewide CHP percentage would be an obligation on the individual utilities based on annual retail sales of gas or electric and other factors which may include market conditions and supply and demand.

The main goal of the CHP PS is to develop and secure a stable and long term funding source for CHP that is not lapsable to the general funds. The CHP PS would be a long term financing incentive similar to the RPS structures. This long term CHP financing structure would be a “smart” portfolio standard. The CHP PS requirement would not be static requirement as in the solar, Class I and Class II RPS. In the RPS case, while the Class I and Class II RPS increases annually through 2021, to change the individual annual RPS, once it is set in rules requires rulemaking. In the case of solar which is set through 2028 it requires legislative action to decrease the RPS and can be increased through regulations. The CHP PS requirement would be a dynamic standard that responds and changes based on market conditions. The criteria for this change would be set as part of the CHP PS Order or rulemaking. Basically it would respond to market demand, overall system costs, overall environmental and energy benefits and overall economic condition to a cap and down to a floor.

Having a portfolio standard that does not change is required and workable in a competitive market like in the solar, Class I and Class II markets. However, in a relatively closed market like CHP it does not make economic sense to have a standard that does not respond to changing market conditions. The CHP capacity would float in terms of CHP supply and demand, costs, environmental/energy benefits and economic factors. These criteria would be designed into the Board’s Order establishing the CHP PS requirement/program and the CHP PS rules. The Board
could revise through its Order the CHP-PS on a going forward basis. The Board would direct the utilities to submit a CHP PS compliance filing consistent with its Order and regulations. The CHP-PS would not be a filing pursuant to N.J.S.A 48:3-98.1 (RGGI filings). The utility CHP annual compliance filing would be based on the CHP-PS requirements established by the Board.

An increasing CHP system demand by customers could increase the CHP-capacity PS up to an annual capacity and cost cap. Likewise decreasing CHP system demand by customers would lower the CHP-PS capacity to a floor value. In addition, if the unit costs for a CHP system were decreasing the CHP capacity could increase to a capacity and cost cap and decrease to a floor if the overall cost for a CHP system were increasing. Likewise as the environmental or energy benefits decreased the CHP capacity could decrease and would increase the CHP capacity if the benefits increased. The Board, through establishment of the criteria for the increase and decrease, would essential regulate this regulated market. This method would minimize the up and down cycles of the market like in the solar market. The CHP PS would develop and implement the most cost effective amount of CHP at the time.

Basically this process of a more directly managed CHP PS would minimize or eliminate the vertical demand curve that impacts the RPS competitive markets in New Jersey. Competitive market based RPS system could result in big swings in the value of the certificates because of market responses to supply and demand. Because of the tens of thousands of potential customers in the solar market, the Solar certificate value changes can be addressed more readily through market forces. Because of the limited number of customers currently in the CHP field this market would benefit initially through a more managed market. This regulated management could change with the implementation of cost effective micro-CHP. At that point the CHP PS market could look more like a solar market for residential and small business market segments.

The CHP long term financing incentives would be limited and specific to new CHP only. The facility would have to generate both electric and useful thermal energy. The PS would define new electric energy and useful thermal energy from the new CHP systems. The CHP long term financing for the electrical EE would have to be more efficient both in terms of the electric energy generated onsite vs. the electricity purchased and the useful thermal energy would have to be more efficient than the central air conditioning it is replacing. In terms of the CHP long term financing for the gas EE, the useful thermal energy would have to be more efficient that the gas heating equipment it is replacing. In addition there would be a requirement for a additional percentage of efficiency above building energy codes. The CHP PS would not include the additional gas used to generate the electricity.

There would be two components to the CHP PS - long term financing structure: one for public critical facilities and another for private sector facilities with dual environmental and economic benefits. Because of the need to immediately address a response to Sandy, the Board could develop the CHP long term financing structure for public critical facilities and then based on experience of the initial program, the private sector component could be added. A public critical facility would be defined as a public facility that could operate 24/7 and either temporarily or long term house, feed and shelter evacuated victims from an emergency such as super storm Sandy.
While the EEPS for CHP could be on both the electric and gas utilities for the more efficient cooling and heating equipment it would be more effective and less confusing to initially address the CHP PS through one - the gas utilities. This current straw for long term CHP financial assistance would be to finance 100 percent of the CHP project through the EEPS obligation on the natural gas utilities. This would be through direct upfront financing by the utilities as a loan. The CHP PS would be a larger version of on the bill financing.

In the direct financing option a portion of the financing would be paid back to the utilities and to the ratepayer over time based on the positive cash flow from the energy saving of the project. This payback period could be limited to a set timeframe. A portion of the direct financing would be forgiven based on performance of the system over time. This performance incentive can be determined upfront in the process or after the end of the payback period.

Initially a feasibility study of the potential project could be performed either funded by the NJCEP or through some other mechanism such as through the state universities. A detailed engineering cost benefit analysis would be required of each project to be financed to document compliance with the payback period and positive cash flow requirements.

While the authority to develop this CHP PS will be through the EEPS provisions in EDECA, this new structure would be developed similar to the EDC SREC financing programs as opposed to the solar, Class I and Class II RPS structure. The natural gas utilities would solicit CHP projects from the public on a set and routine schedule- once every 6 months or once a quarter. Based on the responses to the solicitation the gas utility would select the most cost effective projects that meet the public critical facility criteria and up to their annual CHP PS limit.

The initial gas utility CHP compliance filing could provide for a long plan to achieve the CHP PS over several years. The subsequent gas utility annual CHP compliance filing approval could adjust the CHP-PS based on review of the criteria as established by the Board. The filing would not be RGGI filing.

The NJCEP rebate/grant structure would stay in place until the CHP long term financing is developed, implemented and available. The current NJCEP rebate/grant structure would transition to the new long term PS financing structure as they are developed. The incentive payment would transition from an up-front rebate/grant to a financing incentive either funded upfront or over time based on performance of electricity generated and energy saved. Moving to a performance based system allows for a more efficient payment of incentives over time.

Through a stakeholder process, the details of the CHP PS- long term financing structure criteria could be developed including but not limited to the following:

1. The eligible technologies and eligible fuel types;
2. The percentage of the facility installation cost covered by the financing incentive;
3. Initial financing or performance payments over time;
4. The cap on the size of the facilities;
5. The definition of public critical facilities;
6. The length of time for repaying the financing;
7. The size of the incentive;
8. The value of the incentive ($/MWh)
9. The criteria to annually revise the CHP capacity requirements including:
   a. Market supply and demand;
   b. Environmental and energy benefits;
   c. Overall system costs; and
   d. Statewide economic conditions.

In order to keep the rate impact for CHP projects neutral, a reduction in the overall Utility E3 and NJCEP SBC cost would be a part of the overall design of a CHP PS long term financing program. As the long term financing structure were developed and implemented the direct utility E3 CHP or NJCEP CHP rebate budgets would be reduced by an equivalent increment. This would result in a reduction of the E3 rate or the SBC rate to insure the net cost to the ratepayer over the same period were, at a minimum, a net zero sum gain. Basically this would result in adding no new cost to the ratepayer.

Other Financing Options for Discussion

Another option for discussion for large scale private facilities is the SBC Credit program. This program has been approved by the Board and could provide up to 50% of the customers SBC funds that they pay in annually up to 50% of the cost. This would be limited to large scale (greater than 1 MW) for private sector facilities that document both environmental and economic benefits. This could include both CHP and fuel cell without heat recovery. The SBC payment is after the facility is constructed and after payments of the SBC funds. The program rules for the SBC Credit program are attached.

Two other public financing options include:

Pool bond financing through the Environmental Infrastructure Trust with NJDEP. This would be limited to large scale projects at water and wastewater treatment facilities; and Pool bond financing through the Counties using the allocation of Qualified Energy Conservation Bonds (QECB). This would be smaller scale public projects.
Planning the System to Include Wind – If we build it will they come?

EBA Northeast Chapter Annual Meeting
June 5, 2013
If we build it, will they come?

Presentation to the Northeast Energy Bar Association
Stefanie A. Brand, Director
New Jersey Division
of Rate Counsel
sbrand@rpa.state.nj.us

If you don't know where you are going, you'll end up someplace else.”
— Yogi Berra
• Planning must first involve an assessment of needs.
• Followed by an assessment of how best to meet those needs.
• Until we know there will be generation offshore we don’t know that there is a need.

FERC Order 1000
• Requires transmission planning to consider state policies.
• Must identify transmission needs driven by public policy requirements and evaluate potential solutions to those needs.
• Does not open the door to have transmission planning dictate state policies.
• Whether NJ ends up with 1100 MW of offshore wind is too uncertain.
• Need to at least get further in the process before considering this project.

• PJM did preliminary modeling at Delaware and Maryland’s request. This modeling assumed 7 GW of offshore wind.
• Found “market efficiency benefits that would need to be weighed/compared against the capital costs of building transmission.”
  Source: 2012 RTEP, Book 1, p. 64.
Cost Allocation Issues

- Revision of project to limit to NJ increases NJ share of costs.
- If line is built to only bring electricity from southern NJ to northern NJ, NJ ratepayers will pay for substantially all of it.

![Cost Symbol]

- Project is not worth the cost if offshore wind is not built.
- Other solutions for bringing electricity from southern NJ to northern NJ are likely to be substantially cheaper.
- Cost of NJ Energy Link = $1.3 billion.
Lots of competition for Ratepayer funds

- Storm response and protection
- Renewable Energy
- Infrastructure Projects
- Everything else – food, rent, etc.

The important question to answer is “What if we build it and they don’t come?”

- If PJM modeling does not clearly show we need it without offshore wind then we need to wait till that process is further along before deciding what new transmission is needed.
- Even if offshore wind is built, need to determine most cost-beneficial transmission solution.
Planning the System to include Wind: If we build it will they come

Mike Kormos
Sr. Vice President, Operations
PJM Interconnection

PJM as Part of the Eastern Interconnection

KEY STATISTICS
- Member companies: 800+
- Millions of people served: 60
- Peak load in megawatts: 163,848
- MWs of generating capacity: 185,600
- Miles of transmission lines: 59,750
- GWh of annual energy: 832,331
- Generation sources: 1,365
- Square miles of territory: 214,000
- States served: 13 + DC

As of 9/7/2012

21% of U.S. GDP produced in PJM
Wind-Powered Generation Clusters in PJM

Order 1000 Issues

Public Policy Requirements

- Planning process must consider public policy requirements and evaluate transmission solutions required to satisfy them.

- No requirement to order transmission to satisfy public policy requirements.
• PJM will work with states to evaluate public policy requirements and any necessary transmission.

• States will decide whether to proceed with transmission to meet their needs.

• Transmission costs will be borne by states sponsoring projects to meet their needs.

**State Agreement Approach**

**State Engagement**

• Independent State Advisory Committee (ISAC)
  – Comprised of state agencies as deemed appropriate by states
  – PJM would perform the analysis and discuss the results with ISAC
  – PJM would inform the Transmission Expansion Advisory Committee of the state input into study assumptions and the results of study analysis for information flow / transparency purposes and vice versa

**ISAC is a communication vehicle for organized input into RTEP studies. It does not decide which projects to include in the RTEP.**
Next Steps

• Order 1000 Compliance filing
  – Develop criteria for selection of public policy to be included in the studies.
  – Process for States to “approve” a project be included in the plan

• Potential for first “proposal window” for projects responding to the public policy study results.
New Jersey Energy Link: Proactive Transmission Development Makes Sense

Energy Bar Association Northeast Chapter Annual Meeting
June 5, 2013, Newark, NJ
Markian Melnyk
Expanding transmission will drive energy costs down

“Transmission constraints reduce the size of markets and increase the potential for the exercise of seller market power. Conversely, the expansion of transmission infrastructure serves to increase the supply of energy and capacity, thereby reducing or resolving price differentials between constrained and unconstrained areas.”*


Powerful pro-consumer reasons to pursue smart transmission development
New Jersey energy geography affects prices; historically and into the future

Population and energy use vs. energy production potential

Salem/Hope Creek: 3,576 MW. Nuclear supplies 52% of the energy used in NJ.

Large industrial, commercial and residential load, plus NYC drain

Source: U.S. Census Bureau Census 2000 Summary file 1 population by census tract.
Examples of proactive development

- Transmission lines built proactively by ratepayers that support large scale wind development:
  - California: Tehachapi project
  - Texas: CREZ transmission lines
  - Midwest: Numerous Multi-value Projects serving “energy zones”
- Failure to develop adequate transmission has a high cost
  - In U.S., wind curtailment is increasing
  - In North Sea, offshore wind farms are stranded by transmission completion delays
Good Planning Gives New Jersey Ratepayers the Most Value by Addressing Multiple Challenges

- Advancing New Jersey policy on offshore wind
- Improving reliability
- Reducing capacity prices
- Reducing energy prices
- Reducing ratepayer impact of offshore wind
Offshore wind established as New Jersey policy

- Offshore Wind Economic Development Act
- New Jersey Renewable Portfolio Standard
  - 22.5% by 2021

“The Offshore Wind Economic Development Act will provide New Jersey with an opportunity to leverage our vast resources and innovative technologies to allow businesses to engage in new and emerging sectors of the energy industry...

My Administration will maintain a strong commitment to utilizing energy as industry in our efforts to make our State a home for growth, as well as a national leader in the windpower movement.”

- Governor Chris Christie
Improving reliability
Submarine and subterranean lines are better protected

Hurricane Sandy, October 29-30, 2012: 2.6 million (65%) of New Jersey customers without power

- Over 140 transmission lines out of service
- 40 generators offline
- 5 million customers without power in PJM region

Reliability Problems
- Instability & overvoltage violations in south Jersey
- Short-circuit capacity and N-1 violations in north Jersey
- Severe weather
- Physical sabotage
- Cyber attack
- Electromagnetic disturbances
Capacity prices in PJM

PJM: “PSEG, is historically transmission constrained . . .”

From the PJM report:

“The only LDA in which prices increased, PSEG, is historically transmission constrained, and did not attract much of the new entry and uprates that are internal to PJM and could not fully benefit from the new entry in other parts of PJM and the increased imports due to the transfer limits into PSEG. Additionally, of the 2,710 MW of announced deactivations since the last BRA, the PSEG zone accounted for 1,408 MW or just over half of the total deactivations in all of PJM since the last BRA . . .” At 31.


Results of recent capacity auction in $/MW-day
Energy prices in northern New Jersey are often determined by expensive marginal units.

PSEG: “volatile periods help to maintain pricing”
Reduce ratepayer impact by delivering offshore wind energy to northern New Jersey where it is most needed.

$516 /MWh

$33 /MWh

Grid congestion keeps inexpensive power from reaching high-priced areas.

PJM finds that an offshore backbone could lower congestion charges in New Jersey by $65 million per year. *

Giving ratepayers more value for their offshore wind investment

### Offshore Wind
- NJ’s biggest renewable energy resource
- Developed at scale, OSW is a source of many thousands of jobs, local manufacturing investment, tax revenues and other benefits

### High-Capacity Offshore Backbone
- Avoids cost of multiple separate radial lines
- Efficient for offshore wind
- Efficient for conventional energy transactions when the winds are calm – which lowers energy prices for ratepayers
- 100% utilization (compare to 40% for radial lines)
- Delivers power to where it’s needed, when it’s needed (Southern, Central, or Northern New Jersey)
- Supports reliability and security through a stronger, storm-resistant grid – which lowers expenditures on future overhead grid upgrades
• Electric superhighway connecting northern, central and southern New Jersey
• Delivers 3,000 megawatts of offshore wind and lower cost energy
• Enough to power 1 million homes
• Strengthens New Jersey’s electric grid
• Reduces the cost of offshore wind
• Enables an industry that will:
  • Create 20,000 jobs *
  • Pump $9 billion into the State’s economy *
  • Add $2.2 billion to State and local government tax revenues *

* Study by IHS Global Insight, a leading global economics and analytics firm
Planning Challenges for Long Distance Renewables and Off-shore Wind

Ralph LaRossa, President – PSE&G

EBA Northeast Chapter Annual Meeting
June 5, 2013

RPS – A Major Emerging Challenge to Electric Grid Performance, Reliability, and Cost

State Renewable Portfolio Standards (RPS) require suppliers to utilize wind, solar and other renewable resources to serve an increasing percentage of total demand. Also reflected in the EIPC process.

Renewable Portfolio Standard Policies

29 states + Washington DC and 2 territories have Renewable Portfolio Standards (6 states and 1 territory have renewable portfolio goals)
Adequate System Flexibility …

**PJM Capacity** by Fuel Source

- **NREL Projected Continuum**

*165,000 megawatts installed capacity available in the PJM region as of 1/04/2012. 1617 MW of which is RE (~5.7%), and 58,576 MW of which are “flexible resources (~35.5%).

California Girds for Electricity Woes

**THE WALL STREET JOURNAL**

Increased reliance on wind, solar power means power production fluctuates

Regulators and energy companies met Tuesday, hoping to hash out a solution to the peculiar stresses placed on the states network by sharp increases in wind and solar energy. Power production from renewable sources fluctuates wildly, depending on wind speeds and weather … experts cautioned that the state could begin seeing problems with reliability as soon as 2015.

Characteristics of Variable Energy Resources …

**WIND**

- Daily - wind is typically more abundant at night, when load is low (i.e., at “light load” conditions)
- Seasonally - wind is typically more abundant in the cool seasons, when loads are lowest

**SOLAR**

- Solar outputs are generally more cyclic and better correlated with load, however, cloud cover can cause significant swings in power output.

...Create Planning and Operational Challenges
Characteristics of Variable Energy Resources …

Transmission System Challenges
• Large blocks of Renewable Energy can cause voltage variability, intermittency, and fluctuations

Solutions to consider
• At the transmission level, a comprehensive approach that includes more than technology deployment is necessary for creating a truly flexible system:
  – Modification to conventional power generation resources
  – Reform Demand Side Management standards
  – Variable generation power management
  – Seeking improvements in interregional planning
  – Improving compensation and allocation for ancillary services
  – Revising interconnection standards
  – Enhancing wind monitoring, forecasting
  – Develop a new layer of bulk and distributed storage options

…Create Planning and Operational Challenges

Long Distance Transmission

• The best resource locations are often far from load centers
• Political interest in integrating them would require expansion of transmission systems
• Present planning, cost-allocation and siting policies and regulations may need to be changed to facilitate such expansion
• Technical options include extra-high-voltage AC and DC lines
  • Advantage of AC include ease of voltage transformation, but higher conductor costs
  • Advantage of DC include higher stability over long distances and lower conductor costs, but substations are significantly more costly because of complex power converter equipment needed to convert DC to AC since transformers only work for AC
• The benefit must be balanced with the high cost and difficulty of siting
Go-forward planning focus needs …

- **On the distribution level** – Invest to strengthen the grid, for additional renewables and to withstand future catastrophic storms like Sandy.

- **On the transmission level** – Plan for flexibility and reliability into both power generation and demand-side management.

- **Transmission Costs** – Allocate them appropriately and fairly to renewable energy projects.

- **Ensure reliability** – Can not lose focus.

- **Pursue renewables cost-effectively** – The role of transmission is to respond to the needs of renewable projects rather than to get ahead of them.

… to keep the grid resilient and reliable
FERC Enforcement and Compliance

EBA Northeast Chapter Annual Meeting
June 5, 2013
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Constellation Energy Commodities Group, Inc.

ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued March 9, 2012)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) between the Office of Enforcement (Enforcement) and Constellation Energy Commodities Group (CCG). This order is in the public interest because it resolves the investigation into whether CCG violated the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2, and the Commission’s regulation prohibiting the submission of inaccurate information, 18 C.F.R § 35.41(b). CCG has agreed to pay a civil penalty of $135,000,000 and to disgorge unjust profits of $110,000,000, including interest. In addition, CCG has instituted and will continue to institute additional compliance measures such as: (1) regular monitoring of profit and loss concentrations in virtual transactions and physical schedules of electric energy; and (2) reviewing and documenting the purpose of virtual transactions. CCG is required to monitor and preserve for no less than five years trader communications, including but not limited to Instant Messages (IMs), emails, and telephone calls. CCG must also submit compliance monitoring reports.

Background

2. In January 2008, Enforcement opened a preliminary, non-public investigation pursuant to Part 1b of the Commission’s regulations of CCG’s physical power trading in and around the New York Independent System Operator’s (NYISO) control area after receiving two anonymous hotline calls related to that trading. After commencing that investigation, Enforcement observed through its own surveillance activities that CCG was engaging in virtual trading in the NYISO that was unprofitable. In addition, on February 19, 2009, the NYISO Department of Market Monitoring and Performance (MMP) informed Enforcement that it had decided to apply mitigation measures against CCG related to its virtual bidding behavior in the NYISO, because its virtual load trading
in NYISO Zone A had contributed to an unwarranted divergence of locational based marginal prices between the day-ahead (DA) and real-time (RT) markets. Based on Enforcement’s surveillance observations and the NYISO’s information, Enforcement opened another preliminary, non-public investigation pursuant to Part 1b to determine whether, in violation of 18 C.F.R. § 1c.2, CCG employed a scheme of trading in the NYISO virtual market to move DA prices in a direction that would benefit its financial contract for differences (CFD) positions. Enforcement thereafter conducted the two investigations jointly.

3. In its investigation, Enforcement examined certain of CCG’s: virtual trading in the NYISO and ISO-New England (ISO-NE); physical DA scheduling between the NYISO and ISO-NE, PJM Interconnection (PJM) and Ontario Independent Electric System Operator (IESO); and CFD positions in the NYISO and ISO-NE. Enforcement examined certain data related to CCG’s East Power Trading Group from January 1, 2007 through February 28, 2009 and, as a result, focused its investigation on trading activity by certain members of the East Power Trading Group over a sixteen month period from September 2007 through December 2008 (the Months of Interest). The members of the East Power Trading Group whose activity was investigated were Joseph Kirkpatrick, Michael Pavo, and Jason Hughes (Kirkpatrick, Pavo and Hughes together the East Traders). Kirkpatrick was the supervisor of Pavo and Hughes. In addition, Enforcement investigated the activity of Maxim Duckworth, CCG’s Managing Director of Portfolio Management and Trading, and Kirkpatrick’s direct supervisor and Pavo and Hughes’ indirect supervisor.

4. During the Months of Interest, CCG participated in energy trading in markets including the NYISO, ISO-NE and PJM. In the Months of Interest, the East Power Trading Group participated in the virtual markets in the NYISO and PJM and in the scheduling of DA physical power between the NYISO and ISO-NE, PJM and IESO, as detailed in the Agreement.

5. CCG’s East Power Trading Group also held CFDs during the Months of Interest, including: swaps that priced off the average DA prices in the NYISO and ISO-NE; swaps that priced off the RT price in PJM; financial transmission rights (FTRs) in ISO-NE and PJM; and transmission congestion contracts (TCCs) in the NYISO. The swap positions investigated by Enforcement settled off the monthly average of the DA price of the Zone/region for which the swap was held. As further described in the Agreement, Enforcement found the size of the swap positions to be substantial. The FTR/TCC positions similarly settled off the DA price for the ISO Zone/region in which they were held. The CFDs investigated by Enforcement in the NYISO predominantly settled off the monthly average DA price in Zones A and G and the CFDs investigated by Enforcement in ISO-NE predominantly settled off the monthly average DA price at Mass Hub.
6. For the period of September 2007 through December 2008, the swap positions entering a month ranged in size from approximately 395 MW/h to approximately 12,274 MW/h in NYISO Zone A, from approximately 125 MW/h to approximately 3,682 MW/h in NYISO Zone G, and from 88 MW/h to 3,350 MW/h in ISO-NE Mass Hub. Over that same time frame, the TCC positions ranged in size from 25 MW/h to 936 MW/h in Zone A and 450 MW/h to 931 MW/h in Zone G.

7. As detailed in the Agreement, Enforcement found a repetitive pattern to the virtual and DA physical trading during the Months of Interest. While the practice varied somewhat from month-to-month and zone-to-zone, the trading behavior can be summarized as follows: (i) when the net CFD position which settled off the average DA price of a region was short, the CCG traders at issue entered virtual supply in the Zone/region on which the CFD settled and/or scheduled the import of DA power into the region on which the CFD settled; and (ii) when the net CFD position which settled off the average DA price of a Zone/region was long, the CCG traders at issue entered virtual load in the Zone/region on which the CFD settled and/or scheduled an export of DA power from the region on which the CFD settled to a neighboring ISO.

8. During the Months of Interest the virtual and physical transactions scheduled by the East Traders were routinely unprofitable.

9. CCG’s compliance training materials recognized that behavior which was uneconomic on a stand alone basis in order to benefit positions in other markets should not be engaged in by its traders and that the Commission would likely consider this market manipulation.

10. When the NYISO investigated CCG’s virtual trading activity in its markets for purposes of examining unwarranted divergence, CCG stated in its communications with the NYISO, that its decisions to participate in the NYISO virtual market were based on market fundamentals and omitted the fact that the virtual trading was directly related to its CFDs.

**Investigation**

A. **Commission Anti-Manipulation Rule**

11. Enforcement concluded that from September 2007 through December 2008, CCG violated the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2, which prohibits any entity from: (1) using a fraudulent device, scheme or artifice, or making a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engaging in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; and (3) in connection with a transaction subject to the jurisdiction of the Commission.
12. Enforcement determined that during the Months of Interest, CCG violated the Anti-Manipulation Rule by entering into virtual transactions and DA physical schedules without regard for their profitability, but with the intent of impacting DA prices in the NYISO and ISO-NE to the benefit of certain significant CFD positions held by CCG.

13. Enforcement also determined that as part of this scheme, CCG combined the use of virtual transactions with DA physical schedules to impact DA prices in NYISO and ISO-NE to benefit the CFD positions that priced off a component of those impacted DA prices.

14. Enforcement determined that CCG’s virtual transactions and DA physical schedules were often large in volume and were scheduled with regularity and persistency. By way of example, Enforcement found that in on-peak Zone A during the Months of Interest the East Traders’ virtual trading represented between approximately 24 and 79 percent of all virtual activity in the Zone when the East Traders placed a trade. Enforcement also concluded that in approximately half of the on-peak Zone A months, the East Traders bid virtually in 100 percent of available hours and only three times did their activity drop below 60 percent of available hours. In half of the on-peak Zone A activity identified in the Months of Interest, Enforcement found that virtual trading comprised between 30 and 40 percent of the Zone’s actual physical load when the East Traders placed a trade. During this same time frame, the East Traders flowed DA on-peak physical power between the NYISO and PJM in 100 percent of the hours in two of the four months identified by staff and their flows represented over 50 percent of the limit of the intertie when it flowed. The East Traders’ DA, on-peak physical flows between the NYISO and Ontario ranged in frequency from approximately 20 to 80 percent in the four months identified and averaged between approximately 20 to 80 percent of the available capacity of the intertie when they flowed.

15. Enforcement also found that CCG impacted the DA price in the various markets in which they engaged in this trading behavior to the benefit of their CFD positions.

16. Based on these findings, Enforcement determined that: (1) CCG’s virtual and physical trading activities during the Months of Interest constituted a fraudulent device, scheme or artifice and that CCG engaged in a course of business that operated as a fraud upon the NYISO and ISO-NE markets; (2) CCG intended to manipulate the NYISO and ISO-NE DA markets for the benefit of its CFD positions during the Months of Interest; and (3) CCG’s manipulative scheme was in connection with transactions subject to the jurisdiction of the Commission all in violation of 18 C.F.R. § 1c.2.

17. Enforcement determined that this manipulation of the physical and virtual markets and the respective DA prices resulted in widespread economic losses to market participants who bought and sold energy in the DA markets of ISO-NE and the NYISO. In addition, this manipulation distorted price discovery for all market participants, which contributes not only to trading decisions, but to a variety of industry-wide determinations.
B. Commission Accurate Information Provision

18. Enforcement concluded that CCG violated 18 C.F.R. § 35.41(b), which requires sellers, such as CCG, to “provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with . . . Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences.”

19. Enforcement determined that Section 35.41(b) of the Commission’s regulations applies to CCG because it is a power marketer that is authorized by the Commission to sell – and it does sell – energy, capacity and certain ancillary services at market-based rates in the NYISO, ISO-NE and PJM.

20. Enforcement determined that CCG violated 18 C.F.R. § 35.41(b) by providing inaccurate and misleading information to the NYISO. Specifically, Enforcement determined that CCG denied that its virtual transactions were related to its CFD positions and instead told the NYISO that the transactions were independent of the CFD positions and were entered into based on market fundamentals.

Stipulation and Consent Agreement

21. Enforcement and CCG have resolved Enforcement’s investigation by means of the attached Agreement. CCG neither admits nor denies that the trading behaviors examined by Enforcement violated the Commission’s rules, regulations, or policies. Also, upon the Effective Date of the Agreement, as that term is defined in the Agreement, the investigation of CCG and of Kirkpatrick, Pavo, Hughes, and Duckworth will terminate.

22. The Agreement requires CCG to pay a $135,000,000 civil penalty to the United States Treasury within ten business days of the Effective Date of the Agreement. CCG will pay disgorgement and interest of $110,000,000, such amount representing unjust profits. The disgorgement shall be paid as follows: (i) $6,000,000 to be divided equally among and paid directly to the NYISO, ISO-NE, PJM, the Midwest ISO, Southwest Power Pool, and the California ISO for use in the enhancement of their surveillance capabilities; and (ii) to a fund set up for the benefit of electric energy consumers in the affected states and from which state agencies in those affected states may make requests for apportionment by a Commission Administrative Law Judge. That fund will be divided among the affected states in the ISOs as follows: NYISO ($78,000,000); ISO-NE ($20,000,000); and PJM ($6,000,000). This distribution is based on the results of staff’s investigation and its assessment of the relative harm imposed on each organized market as a result of CCG’s trading. Specifically, the allocation was based on the megawatts associated with DA schedules flowing between the ISOs and virtual transactions within NYISO that were part of what staff determined to be CCG’s manipulative scheme.
23. Since the onset of Enforcement’s investigation, CCG instituted additional procedures to monitor the profit and loss concentrations in virtual transactions and DA physical schedules of electric energy and to document the purpose of virtual transactions.

24. The Agreement requires CCG and any successor company to retain communications by its traders, including, but not limited to, IMs, emails and telephone calls, for a period of no less than five years and to regularly monitor those communications for irregularities or illegalities.

25. The Agreement requires CCG and any successor company to submit semi-annual compliance monitoring reports to Enforcement staff for two years following the Effective Date of the Agreement, with the option of a third year of compliance monitoring reports at Enforcement’s discretion. Each compliance report shall describe any new and existing compliance program measures, including training, and alert Enforcement staff to any violations that may occur.

26. Under the Agreement, Pavo, Hughes, and Duckworth will not hold a position which involves physical and financial energy trading at CCG or a successor company in the future. CCG has also agreed that Kirkpatrick will not hold any such position at CCG or a successor company in the future.

**Determination of the Appropriate Civil Penalty**

27. Pursuant to section 316A(b) of the FPA, the Commission may assess a civil penalty up to $1,000,000 for each day that the violation continues. In determining the appropriate remedy, Enforcement considered the factors described in section 316A(b) of the FPA and in the Revised Policy Statement on Penalty Guidelines. Specifically, Enforcement considered that: CCG’s conduct was serious and was committed willfully and intentionally; CCG’s conduct was committed through the participation or oversight of CCG’s Managing Director of Portfolio Management and Trading and therefore involved upper management; the conduct involved more than 100,000 MWh of electricity and continued for more than 250 days; CCG’s compliance program was not effective at the time; and CCG’s actions caused harm and impacted the DA price in the Commission’s jurisdictional markets.

28. We conclude that the penalties, disgorgement, the enhanced compliance measures, and the compliance monitoring reports set forth in the Agreement are a fair and equitable

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resolution of this matter and are in the public interest, as they reflect the nature and seriousness of CCG’s conduct. 3

The Commission orders:

The attached Stipulation and Consent Agreement is hereby approved without modification.

( S E A L )

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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3 The civil penalty falls within a range consistent with the Penalty Guidelines. Application of the Penalty Guidelines in this case furthers the goal of “add[ing] greater fairness, consistency, and transparency to our enforcement program.” Id. at P 2. We have considered the factors set forth in the Revised Policy Statement on Penalty Guidelines and have concluded that the penalty in this case is appropriate.
STIPULATION AND CONSENT AGREEMENT

I. Introduction

1. The staff of the Office of Enforcement (Enforcement) of the Federal Energy Regulatory Commission (Commission) and Constellation Energy Commodities Group, Inc. (CCG) enter into this Stipulation and Consent Agreement (Agreement) to resolve an investigation conducted under Part 1b of the Commission’s regulations, 18 C.F.R. Part 1b (2011). The investigation examined CCG’s physical and financial electric energy trading activities in and around the New York Independent System Operator’s (NYISO) Control Area, and in other RTOs, as described herein. Specifically, the investigation examined potential violations of the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2, and of the Commission’s regulation prohibiting the submission of inaccurate information, 18 C.F.R. § 35.41(b).

II. Stipulations

Enforcement and CCG hereby stipulate and agree to the following facts:

2. In January 2008, Enforcement was contacted anonymously by two entities who questioned whether CCG may have manipulated the prices of electric energy in the NYISO for the period December 2007 through January 2008. Upon review, Enforcement determined that this information warranted further investigation. Enforcement opened a preliminary, non-public investigation pursuant to Part 1b of the Commission’s regulations of CCG’s physical power trading in and around the NYISO.

3. After commencing that investigation, Enforcement observed through its own surveillance activities that CCG was engaging in virtual trading in the NYISO that was unprofitable. In addition, on February 19, 2009, the NYISO Department of Market Monitoring and Performance (MMP) informed Enforcement that it had decided to apply mitigation measures against CCG related to its virtual bidding behavior in the NYISO. Specifically, the NYISO determined that from October 1 to November 18, 2008, CCG’s virtual load trading in NYISO Zone A had contributed to an unwarranted divergence of locational based marginal prices (LBMP) between the day-ahead (DA) and real-time
(RT) markets. Based on Enforcement’s surveillance observations and the NYISO’s information, Enforcement opened a preliminary, non-public investigation pursuant to Part 1b of the Commission’s regulations to determine whether, in violation of 18 C.F.R. § 1c.2, CCG employed a scheme of trading in the NYISO virtual market to move DA prices in a direction that would benefit its contract for differences (CFD) positions. Due to similarities in the geographical regions and trading behavior at issue, Enforcement jointly conducted the two investigations. The Enforcement examination, as described in greater detail in Sections I and II herein, constitutes the Investigation.

4. In its Investigation, Enforcement examined certain of CCG’s: virtual trading in the NYISO and ISO-New England (ISO-NE); physical DA scheduling between the NYISO and ISO-NE, PJM Interconnection (PJM) and Ontario Independent Electric System Operator (IESO); and CFD positions in the NYISO and ISO-NE. Enforcement examined certain data, submitted pursuant to 18 C.F.R. §1b.9, related to the East Power Trading Group from January 1, 2007 through February 28, 2009 and, as a result, focused its Investigation on trading activity by certain members of the East Power Trading Group over a sixteen month period from September 2007 through December 2008 (the Months of Interest). Enforcement initially considered data related to virtual trading and DA physical schedules by certain members of the East Power Trading Group in the Midwest Independent System Operator (MISO) from January 1, 2007 through December 31, 2008, but did not discover conduct in MISO that warranted further investigation.

5. During the Months of Interest, CCG participated in speculative energy trading in markets including the NYISO, ISO-NE and PJM. In the Months of Interest, CCG’s East Power Trading Group participated in the virtual markets in the NYISO and PJM and in the scheduling of DA physical power between the NYISO and ISO-NE, PJM and IESO.

6. In the Months of Interest, CCG’s East Power Trading Group also held CFDs, including: swaps that priced off the average DA prices in the NYISO and ISO-NE; swaps that priced off the RT price in PJM; financial transmission rights (FTRs) in ISO-NE and PJM; and transmission congestion contracts (TCCs) in the NYISO.

7. The CFDs investigated by Enforcement were held either in the books of Joseph Kirkpatrick, Managing Director of East Power Trading, or, when Kirkpatrick was stopped-out of his books on at least two occasions, Maxim Duckworth, whose title was Managing Director of Portfolio Management and Trading for all but two of the Months of Interest and of which East Power Trading was a part, placed and held those CFD positions in his book. While the CFDs were in Duckworth’s book on these occasions, the virtual and DA physical schedules remained in Kirkpatrick’s books.

8. The virtual transactions and DA physical schedules investigated by Enforcement were placed or ordered to be placed predominantly by Michael Pavo, Vice President in East Power Trading, and Jason Hughes, Associate in East Power Trading. Kirkpatrick was Pavo and Hughes’ direct supervisor (Kirkpatrick, Pavo and Hughes, collectively, the
East Traders). Duckworth was Kirkpatrick’s direct supervisor and the indirect supervisor to Pavo and Hughes.

9. The swap positions held in Kirkpatrick’s or Duckworth’s books and investigated by Enforcement settled off the monthly average of the DA price of the Zone/region for which the swap was held. The FTR/TCC positions similarly settled off the DA price for the ISO Zone/region in which they were held. The CFDs investigated by Enforcement in the NYISO predominantly settled off the monthly average DA price in Zones A and G and the CFDs investigated by Enforcement in ISO-NE predominantly settled off the monthly average DA price at Mass Hub.

10. For example, for the period of September 2007 through December 2008, the swap positions entering a month ranged in size from approximately 395 MW/h to approximately 12,274 MW/h in NYISO Zone A, from approximately 125 MW/h to approximately 3,682 MW/h in NYISO Zone G, and from 88 MW/h to 3,350 MW/h in ISO-NE Mass Hub. Over that same time frame, the TCC positions held by or for the benefit of Mr. Kirkpatrick’s books ranged in size from 25 MW/h to 936 MW/h in Zone A and 450 MW/h to 931 MW/h in Zone G.

11. Enforcement found a repetitive pattern to the virtual and DA physical trading scheduled by the East Traders during the Months of Interest. While the practice varied somewhat from month-to-month and zone-to-zone, the trading behavior can be summarized as follows: (i) when the net CFD position which settled off the average DA price of a region was short, the East Traders entered virtual supply in the Zone/region on which the CFD settled and/or scheduled the import of DA power into the region on which the CFD settled; and (ii) when the net CFD position which settled off the average DA price of a Zone/region was long, East Traders entered virtual load in the Zone/region on which the CFD settled and/or scheduled an export of DA power from the region on which the CFD settled to a neighboring ISO.

12. Thus, for example, when there was an on-peak or off-peak net long CFD position in NYISO Zone A during the Months of Interest, the East Traders generally bid virtual load in Zone A and/or Zone B. In addition, the East Traders also scheduled DA exports of physical power from the NYISO to IESO or from NYISO to PJM. Conversely, when there was an on-peak or off-peak net short CFD position in NYISO Zone A, the East Traders generally offered virtual supply in Zone A. In addition, the East Traders also scheduled DA imports of physical power into New York from IESO and/or into NYISO from PJM.

13. During most of the Months of Interest in which Kirkpatrick held CFD positions in Zone A, he also held a spread between Zone G in the NYISO and ISO-NE. For example, when Kirkpatrick was net long Zone G swaps (and often net short ISO-NE swaps), the East Traders generally bid virtual load in Zones G or H or scheduled DA physical flows from the NYISO to ISO-NE. In some months the East Traders combined these strategies,
for example, by bidding virtual load in Zones G or H at the same time or by combining virtual load bids in Zones G or H with physical flows from the NYISO to ISO-NE.

14. During the Months of Interest the virtual and physical transactions scheduled by the East Traders were routinely unprofitable.

15. CCG’s compliance training materials recognized that behavior which was uneconomic on a stand alone basis in order to benefit positions in other markets should not be engaged in by its traders and that the Commission would likely consider this market manipulation.

16. When the NYISO investigated CCG’s virtual trading activity in its markets for purposes of examining unwarranted divergence, the NYISO’s MMP conducted a conference call with and received written correspondence from CCG. In its communications with the NYISO, CCG stated that its decisions to participate in the NYISO virtual market were based on market fundamentals and omitted the fact that the virtual trading was directly related to its CFDs. Participants on behalf of CCG in the conference call between CCG and the NYISO’s MMP included Pavo and Hughes.

III. Violations

A. Enforcement Determined that CCG Engaged in Market Manipulation

17. Enforcement determined that, during the Months of Interest, CCG violated the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2. Specifically, Enforcement determined that CCG entered into virtual and DA physical schedules with the intent of impacting DA prices in the NYISO and ISO-NE to the benefit of the CFD positions held in Kirkpatrick’s or Duckworth’s books. The Commission’s Anti-Manipulation Rule prohibits any entity from: (1) using a fraudulent device, scheme or artifice, or making a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engaging in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; (3) in connection with a transaction subject to the jurisdiction of the Commission.

18. Enforcement determined that the size of the swap positions held in Kirkpatrick’s or Duckworth’s books was significant.

19. Enforcement found that Kirkpatrick, Duckworth, Pavo and Hughes each did not concern himself with the profitability of the virtual trades or the DA physical schedules.

20. Enforcement determined that CCG’s virtual and DA physical schedules were entered into without regard to their economics or market fundamentals and were instead
entered into solely with the intent to impact DA price in the NYISO and ISO-NE to the benefit of the CFD positions.

21. Specifically, Enforcement determined that during the Months of Interest, when the net CFD position which settled off the monthly average DA price in a region was short, the CFD (and thus CCG) would benefit from a decrease in DA price in that region. Enforcement concluded that the East Traders usually entered virtual supply in and/or imported into the region on which the CFDs were priced. Enforcement found that the price impact of the East Traders’ virtual and/or physical behavior was to decrease the DA price in that region, to the benefit of the CFD position.

22. Further, Enforcement determined that during the Months of Interest, when the net CFD position which settled off the monthly average DA price in a region was long, the CFD (and thus CCG) would benefit from an increase in DA price in that region. Enforcement concluded that the East Traders usually entered virtual load in and/or exported out of the region on which the CFDs were priced. Enforcement found that the price impact of the East Traders’ virtual and/or physical behavior was to increase the DA price in that region, to the benefit of the CFD position.

23. Enforcement observed evidence of this pattern in the virtual trading and scheduling of DA physical power engaged in by CCG, which demonstrated that the virtual and physical trading behavior supported the CFDs in the Months of Interest. For example, in January 2008 Zone A on-peak, Duckworth’s books held a net long CFD position of approximately 7,114 MW/h on average. Beginning in early January 2008, Kirkpatrick’s CFDs had been transferred to Duckworth’s books when Kirkpatrick was stopped out. Also, at this time, the East Traders bid and cleared approximately 500-800 MW/h of virtual load bids. In addition, the East Traders exported more than 1000 MW/h of day-ahead physical power from the NYISO to Ontario for six on-peak days. Moreover, CCG cleared approximately 400-500 MW/h in virtual load bids for four on-peak days in Zone B. On the other hand, in February Zone A on-peak, the net CFD position became short approximately 2600 MW/h on average and the East Traders cleared an average of approximately 589 MW/h of virtual supply offers. In addition, the East Traders scheduled imports of approximately 397 MW/h on average of DA physical power from IESO to the NYISO for most of the month. For six out of the nineteen on-peak days, those imports were up to 1000 MW/h.

24. Enforcement determined that the NYISO virtual transactions and DA physical trades scheduled by the East Traders for the benefit of Kirkpatrick were often large in volume and were scheduled with regularity and persistency. By way of example, Enforcement found that in on-peak Zone A during the Months of Interest the East Traders’ virtual trading represented between approximately 24 and 79 percent of all virtual activity in the Zone when the East Traders placed a trade. Enforcement also concluded that in approximately half of the on-peak Zone A months, the East Traders bid virtually in 100 percent of available hours and only three times did their activity drop
below 60 percent of available hours. In half of the on-peak Zone A activity identified in the Months of Interest, Enforcement found that virtual trading comprised between 30 and 40 percent of the Zone’s actual physical load when the East Traders placed a trade. During this same time frame, the East Traders flowed DA on-peak physical power between the NYISO and PJM in 100 percent of the hours in two of the four months identified by staff and their flows represented over 50 percent of the limit of the intertie when it flowed. The East Traders’ DA, on-peak physical flows between the NYISO and Ontario ranged in frequency from approximately 20 to 80 percent in the four months identified and averaged between approximately 20 to 80 percent of the available capacity of the intertie when they flowed.

25. During the Months of Interest, Enforcement determined that the East Traders also combined the use of virtuals with scheduling DA physical trading. For example, while the virtuals in Zone A on-peak were being bid 100 percent of the time in January 2008, at a total that represented approximately 27 percent of the Zone’s actual load and approximately 48 percent of all virtuals in the Zone, the East Traders were also flowing DA power from the NYISO to Ontario at an amount that approached 80 percent of the available capacity for the intertie when the East Traders flowed for about 30 percent of the hours. And again, for example, in on-peak February 2008, while the East Traders’ virtual trading was close to 100 percent of all of the virtuals in Zone H, they also participated in 100 percent of the hours available for flowing power between the NYISO and ISO-NE at an average level that was over 80 percent of the intertie limit when it flowed.

26. Enforcement determined that the DA price was the ultimate arbiter of profitability of the CFD positions held by Kirkpatrick and/or Duckworth, as each of these CFD positions priced off a component of the DA price. In addition, as the volume of the virtual and physical trading engaged in by CCG was so large and so persistently repetitive -- despite the fact that the trades were unprofitable -- Enforcement concluded that CCG intended to impact the DA price in the Zones/regions in which the trading was engaged. Enforcement also determined that through their actions CCG affirmatively impacted the DA price in the various markets in which they engaged in this activity to the benefit of their CFD positions.

27. Enforcement alleged that Kirkpatrick intended to and did manipulate the DA markets in the NYISO and ISO-NE from September 2007 through at least September 2008. Kirkpatrick left the physical employ of CCG in October 2008 although he still remained in a consulting arrangement until late February 2009. Enforcement alleged that Kirkpatrick knew that: (i) physical transactions impact DA price and that he intended to impact price with physical transactions scheduled for his benefit; (ii) virtual transactions impact DA price and that he intended to impact price with virtual transactions scheduled for his benefit; and (iii) the virtual and physical transactions together impact DA price.
and that he intended to impact DA price with physical and virtual transactions scheduled for his benefit.

28. Enforcement alleged that Pavo and Hughes intended to and did engage in a scheme to manipulate the DA markets in the NYISO and ISO-NE during the Months of Interest. Enforcement alleged that evidence adduced during the investigation demonstrated that Pavo and Hughes each understood that the DA physical schedules and virtual transactions impacted DA price and that each intended to impact DA price through the placement of those schedules.

29. Enforcement alleged that Duckworth actively participated in the trading scheme to manipulate DA prices in the NYISO and ISO-NE during the Months of Interest. Enforcement alleged that evidence adduced during the investigation demonstrated that Duckworth took proactive steps to ensure that the East Traders could and would continue to trade virtually and physically to improve the value of Kirkpatrick’s CFD positions.

30. Based on these findings, Enforcement determined that CCG intended to and did manipulate the NYISO and ISO-NE DA markets for the benefit of its CFDs during the Months of Interest. Enforcement also determined that Duckworth was a member of upper management and thus CCG’s upper management understood the relationship between the virtual and DA physical strategy and the CFDs. Enforcement also determined that information concerning the manner in which the East Traders were trading was available to Duckworth and other CCG senior managers through CCG’s electronic database. However, Enforcement determined that no one in upper management, including Duckworth, reviewed these virtual trades and DA physical schedules. In addition, Enforcement determined that while CCG’s Risk Management Group was concerned about the size of Kirkpatrick’s positions and brought those concerns to the level of upper management, the concerns were not addressed.

31. Enforcement determined that this manipulation of the physical and virtual markets and the respective DA prices resulted in economic losses to market participants who bought and sold energy in the DA markets of ISO-NE and the NYISO. In addition, this manipulation distorted price discovery for all market participants, which contributes not only to trading decisions, but to a variety of industry wide determinations.

32. Enforcement determined that these actions were a fraudulent device, scheme or artifice and that CCG engaged in a course of business that operated as a fraud upon the NYISO and ISO-NE in the Months of Interest in violation of 18 C.F.R. § 1c.2.

B. Enforcement Determined that CCG Violated Accuracy Provisions

33. Enforcement determined that CCG violated the accuracy requirements of Commission regulations, 18 C.F.R. § 35.41(b). Section 35.41(b) of the Commission’s regulations applies to CCG because it is a power marketer that is authorized by the
Commission to sell -- and it does sell -- energy, capacity and certain ancillary services at market-based rates in the NYISO, ISO-NE and PJM. This section requires CCG to “provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with…Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences.”

34. Enforcement determined that CCG violated 18 C.F.R. § 35.41(b) by affirmatively providing misleading information to the NYISO. Specifically, Enforcement determined that CCG denied that its virtual transactions were related to its CFDs and instead told the NYISO MMP that the transactions were independent of the CFD positions and were entered into based on market fundamentals.

35. Enforcement further determined that CCG’s failure to provide accurate information to the NYISO MMP provided additional evidence to Enforcement of CCG’s scheme to manipulate the virtual and physical markets to impact DA price.

IV. Remedies and Sanctions

36. For purposes of settling any and all civil and administrative disputes arising out of, related to, or connected with Enforcement’s Investigation, CCG agrees with the facts as stipulated in Section II of this Agreement but neither admits nor denies the violations described in Section III of this Agreement. CCG agrees to take the following actions:

    A. Disgorgement

37. CCG shall disgorge unjust profits and interest of $110,000,000 within ten business days after the direction set forth in subpart (g) below. The entirety of the $110,000,000, which is not a civil penalty, shall be distributed as follows:

    a. a total of $6,000,000 will be distributed directly to and equally among the NYISO, ISO-NE, PJM, Midwest-ISO, Southwest Power Pool and the California ISO for the purposes of purchasing computer hardware and/or software that improves their respective surveillance and analytic capabilities, in consultation with the Commission’s Director of the Office of Enforcement;

    b. the remaining funds will be deposited, as follows, into a fund for the benefit of electric energy consumers in the affected states within the NYISO ($78,000,000), ISO-NE ($20,000,000) and PJM ($6,000,000) (the Fund);

    c. any requests for apportionment of the monies in the Fund by the affected states within the NYISO, ISO-NE and PJM may only be
made by the appropriate state agency or agencies of those respective
states, including, for example, state public service commissions,
state attorneys general, or state consumer advocates, for the benefit
of electric energy consumers;

d. these requests will be filed with and decided by a Commission
Administrative Law Judge (ALJ);

e. the apportionment process will be determined by the ALJ;

f. neither CCG nor any of its successors or affiliates, or their agents
officers, directors or current or former employees, or related entities
shall have any role, including, but not limited to the role of
intervenor or amicus, in the ALJ’s apportionment of the funds or any
proceedings concerning the requests made for apportionment of the
monies in the Fund;

g. CCG will deposit the monies for the Fund into a United States
Treasury account, as directed by the Commission’s Director of the
Office of Enforcement, and CCG will provide the monies specified
above in subparagraph (a) to the ISOs and RTOs pursuant to the
direction of the Commission’s Director of the Office of
Enforcement; and

h. the final disposition of the Fund, including the amount of each
allocation and identity, to the extent known, of the recipient(s) shall
be made public by the ALJ.

B. Civil Penalty

38. CCG shall pay a civil penalty of $135,000,000 to the United States Treasury, by
wire transfer, within ten business days after the Effective Date of this Agreement, as
declared below.

C. Compliance

39. Since the onset of Enforcement’s investigation, CCG has taken steps to implement
enhancements to its compliance program. Specifically, CCG instituted a new policy and
process to monitor profit and loss concentrations in virtual transactions and physical
schedules of electric energy and to review and document the purpose of virtual
transactions. This monitoring had not been done previously. The monitoring is to be
performed in a manner such that improper trading may be readily identified by CCG
should it occur in the future.
40. In addition to the enhancements already in effect at CCG as described above, CCG agrees that CCG, and any successor companies, develop and enforce policies which require that communications by its traders, including but not limited to instant messaging (IMs), email, and phone calls, will be retained by CCG for a period of no less than five years. In addition, CCG agrees that CCG, and any successor companies, set up a system whereby such communications will be regularly monitored by its compliance group for potential irregularities or illegalities. CCG agrees that these policies will be made fully effective within 90 days after the Effective Date of this Agreement.

41. CCG shall adopt or maintain compliance measures and procedures related to its trading of jurisdictional products, including virtual transactions, scheduling of physical power, TCCs and FTRs. These measures shall include improved training for its traders, supervisors, and managers regarding the Commission’s regulations prohibiting manipulation of jurisdictional energy markets and the Commission’s regulations governing energy trading, including the adherence to the tariffs in the organized markets in which CCG participates and providing accurate information to the Commission, RTOs and ISOs. CCG shall make semi-annual compliance monitoring reports to Enforcement for two years following the Effective Date of this Agreement. The first semi-annual compliance monitoring report shall be submitted no later than ten days after the end of the second calendar quarter after the quarter in which the Effective Date of this Agreement falls. The period covered by the report shall consist of the six months ending one calendar month prior to the date of such report. The second semi-annual compliance monitoring report shall be submitted six months thereafter for the six month period succeeding the prior reporting period. The third and fourth semi-annual compliance monitoring reports shall follow the same schedules.

42. Each compliance monitoring report shall: (1) advise Enforcement whether violations of Commission regulations have occurred during the applicable period; (2) provide a detailed update of all compliance measures and procedures instituted, and compliance training administered, by CCG in the applicable period, including a description of the compliance measures and procedures instituted, the compliance training provided to all relevant personnel concerning the Commission’s energy trading, accuracy and anti-manipulation regulations, and a statement of the personnel or other evidence demonstrating that the personnel have received such training and when the training took place; and (3) include an affidavit executed by an officer of CCG that the compliance monitoring reports are true and accurate. Upon request by Enforcement, CCG shall provide to Enforcement documentation to support its reports. After the receipt of the fourth semi-annual report, Enforcement may, at its sole discretion, require CCG to submit semi-annual reports for one additional year.
43. Moreover, CCG represents that by the Effective Date of this Agreement, its current employees, Duckworth, Pavo and Hughes, shall be removed from any position at CCG where any of these individuals engage in or perform any duties related to managing, directing, or engaging in wholesale physical and financial energy trading (a CCG Trading Position). CCG similarly agrees that Duckworth, Pavo and Hughes will not hold any CCG Trading Position as long as each is within the employ of CCG or any successor or affiliate. Kirkpatrick is not currently employed by CCG, and will not hold any CCG Trading Position in the future.

V. Terms

44. The Effective Date of this Agreement shall be the later of the date on which: (a) the Commission issues an order approving this Agreement without material modification; or (b) the merger pursuant to the Agreement and Plan of Merger among Constellation Energy Group, Inc., Exelon Corporation, and Bolt Acquisition Corporation, dated April 28, 2011, is consummated. When effective, this Agreement shall resolve the matters specifically addressed herein as to CCG and any affiliated entity, and their agents, officers, directors and employees, both past and present, and any successor in interest to CCG.

45. Upon the Effective Date of this Agreement, the Commission shall release CCG and any successor or affiliate, Kirkpatrick, Pavo, Hughes, and Duckworth and forever bar the Commission from holding CCG and any successor or affiliate, and their respective agents, officers, directors and employees, both past and present, liable for any and all administrative or civil claims, known or unknown, arising out of, related to, or connected with the Investigation as defined in this Agreement. Moreover, upon the Effective Date of this Agreement, the Investigation of CCG, Kirkpatrick, Pavo, Hughes, and Duckworth shall terminate.

46. CCG’s failure to: (a) make a timely civil penalty payment; (b) make a timely disgorgement payment as set forth in paragraph 37 above; (c) comply with the compliance requirements specified herein; or (d) comply with any other provision of this Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act, 16 U.S.C. § 792, et seq., and may subject CCG and any successor companies to additional action under the enforcement and penalty provisions of the Federal Power Act.

47. If CCG fails to make the civil penalty and disgorgement payments described above at the times agreed by the parties, interest payable to the United States Treasury will begin to accrue pursuant to the Commission’s regulations at 18 C.F.R. § 35.19(a)(2)(iii)(A) (2011) from the date the payments are due, in addition to any other enforcement action and penalty that the Commission may take or impose.
48. This Agreement binds CCG and its agents, successors, and assigns. The Agreement does not create any additional or independent obligations on CCG, or any affiliated entity, its agents, officers, directors, or employees, other than the obligations identified in this Agreement.

49. The signatories to this Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer, or promise of any kind by any member, employee, officer, director, agent, or representative of Enforcement or CCG has been made to induce the signatories or any other party to enter into the Agreement.

50. Unless the Commission issues an order approving this Agreement in its entirety and without material modification, the Agreement shall be null and void and of no effect whatsoever, and neither Enforcement nor CCG shall be bound by any provision or term of this Agreement, unless otherwise agreed to in writing by Enforcement and CCG.

51. In connection with the payment of the civil penalty provided for herein, CCG agrees that the Commission’s order approving this Agreement without material modification shall be a final and unappealable order assessing a civil penalty under § 316A(b) of the Federal Power Act, 16 U.S.C. § 825o-1(b). CCG waives findings of fact and conclusions of law, rehearing of any Commission order approving this Agreement without material modification, and judicial review by any court of any Commission order approving this Agreement without material modification.

52. This Agreement may be modified only if in writing and signed by CCG and Enforcement. No waiver of any provision of this Agreement or departure from any term of this Agreement shall be effective unless in writing and signed by CCG and Enforcement. No modification will be effective unless any approval of the Commission that may be required with respect to such modification has been received.

53. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity, and accepts this Agreement on the entity’s behalf.
54. The undersigned representative of CCG affirms that he or she has read this Agreement, that all of the matters set forth in this Agreement are true and correct to the best of his or her knowledge, information, and belief, that he or she understands that this Agreement is entered into by Enforcement in express reliance on those representations, and that he or she has had the opportunity to consult with counsel.

55. This Agreement may be signed in counterparts.

Agreed to and Accepted:

Norman Bay  
Director, Office of Enforcement  
Federal Energy Regulatory Commission  
Date: 3-8-12

CCG  
By: Charles A. Berardesco  
Its: Corporate Secretary  
Date: 3-8-12
ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(issued January 22, 2013)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) between the Office of Enforcement (Enforcement) and DB Energy Trading LLC (Deutsche Bank). The Commission determines this order is in the public interest because it provides fair and equitable resolution of the Order to Show Cause proceeding in this docket as well as Enforcement’s investigation under Part 1b of the Commission’s regulations, 18 C.F.R. Part 1b (2012). This proceeding and Enforcement’s investigation addressed Deutsche Bank’s conduct in the markets of the California Independent System Operator Corporation (CAISO). The investigation examined possible violations of the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2, and of the Commission’s regulation prohibiting the submission of inaccurate information, 18 C.F.R. § 35.41(b).\(^1\)

2. Deutsche Bank neither admits nor denies the violations and agrees to pay a civil penalty of $1,500,000; disgorge unjust profits of $172,645, plus interest; and implement improved compliance training and procedures.

I. Background

3. As described in the Agreement, Deutsche Bank is an indirect, wholly-owned subsidiary of Deutsche Bank AG. Deutsche Bank has market-based rate authority.\(^2\) For the period investigated, January 29, 2010 through March 24, 2010 (Referral Period), Deutsche Bank purchased and sold energy and Congestion Revenue Rights (CRRs) in the CAISO markets. Deutsche Bank conducted its trading in CRRs and Financial

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\(^1\) Enforcement staff also examined violations of similar provisions contained in then-applicable CAISO Tariff, CAISO Fourth Replacement Tariff, Conformed Fourth Replacement CAISO Tariff (Tariff), § 37.5.1 (accuracy) and § 37.7 (manipulation).

\(^2\) DB Energy Trading, LLC, 109 FERC ¶ 61,125 (2004); DB Energy Trading LLC, Docket No. ER04-1222-001 (December 8, 2008) (delegated letter order).
Transmission Rights (FTRs) through its FTR desk. In the CAISO markets, the traders on that desk (CRR traders) focused exclusively on bidding on CRRs and had no responsibility for physical trading until they undertook the physical trades at issue in this matter.

4. Following a referral by the CAISO Department of Market Monitoring, Enforcement opened a non-public, preliminary investigation of Deutsche Bank to determine whether it violated the Commission’s regulations and the CAISO Tariff.

5. Enforcement concluded that Deutsche Bank violated the Commission’s Anti-Manipulation Rule, 18 CFR § 1c.2, by trading in one product, physical exports at Silver Peak, with the intent to benefit a second product, its CRR position at Silver Peak. Enforcement also concluded that Deutsche Bank’s designation of its physical trades as Wheeling-Through transactions violated the accuracy requirements of Commission regulations, 18 CFR § 35.41(b).

6. Enforcement set forth its conclusions in a report to the Commission. Based on that report, on September 5, 2012, the Commission issued an Order to Show Cause and Notice of Proposed Penalty. On November 5, 2012, Deutsche Bank submitted an Answer to that order. On the day Enforcement staff’s Reply to that Answer was due, January 11, 2013, the Commission issued a notice postponing the filing date of the Reply in light of the fact that Enforcement staff and Deutsche Bank had entered into settlement negotiations.

II. **Stipulation and Consent Agreement**

7. In those negotiations, Enforcement staff and Deutsche Bank resolved this matter by means of the attached Agreement.

8. Deutsche Bank stipulates to the facts recited in the Agreement.

9. Deutsche Bank entered the Referral Period holding a quarterly CRR position with a source internal to CAISO and a sink at the Silver Peak intertie between CAISO and the Sierra Pacific Power Company (SPPC) control area. This CRR position benefitted Deutsche Bank when export congestion occurred at Silver Peak and caused losses to Deutsche Bank when import congestion occurred at Silver Peak.

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10. On January 15, 2010, CAISO derated the Silver Peak intertie, allowing no net energy to flow in the import direction and limiting flows in the export direction. The derate did not prevent bidding and scheduling in both directions because exports could be offset by imports. Once the derate became effective on the trading day of January 19, 2010, import congestion at Silver Peak caused Deutsche Bank to lose money on its CRR position.

11. In response, on January 26, 2010, during CAISO’s auction for February CRRs, Deutsche Bank obtained CRRs that partially decreased its exposure to import congestion at Silver Peak.

12. To negate Deutsche Bank’s remaining exposure, as of January 29, 2010, Deutsche Bank’s CRR traders exported physical energy at the Silver Peak intertie in order to eliminate the import congestion that was causing losses to its CRR positions (the Export Strategy). As stipulated by Deutsche Bank, its “exports at Silver Peak raised prices at Silver Peak and caused its CRR position to gain value.”

13. When Deutsche Bank exported at Silver Peak, no import congestion appeared at Silver Peak and Deutsche Bank’s CRR position did not experience losses. For a small number of hours, Deutsche Bank contributed to export congestion that not only resulted in avoided losses but also increased the value of its CRR position. In both instances, the physical transactions were intended to, and did, benefit the CRR position.

14. Deutsche Bank implemented its Export Strategy by scheduling physical energy on transmission external to the CAISO system from Silver Peak to the Summit intertie and self-scheduling paired physical transactions consisting of exports (purchases) at Silver Peak and an equal amount of imports (sales) at Summit. Deutsche Bank falsely designated many of its physical transactions as Wheeling-Through transactions. Inside the CAISO, the Wheeling-Through designation led CAISO to conclude that Deutsche Bank was wheeling power from Summit to Silver Peak. Outside the CAISO, Deutsche Bank scheduled energy and transmission from the export point, Silver Peak, to the import point, Summit. The relevant CAISO Tariff required a Wheeling-Through transaction to have a resource outside of CAISO and a Load outside of CAISO. Deutsche Bank,

4 Tariff, § 30.5.4 (incorporating definition of Wheeling-Through); Tariff Appendix A, “Master Definitions Supplement” (defining Wheeling-Through); see also Tariff, § 1.2 (“Capitalized terms used in this CAISO Tariff shall have the meanings set forth in the Master Definitions Supplement.”).
however, lacked a resource or a Load outside the CAISO for its designated Wheeling-Through transactions.

15. As noted above, the CRR traders focused exclusively on bidding on CRRs and, until they undertook the physical transactions at issue in this matter, had no responsibility for physical trading. They undertook the physical transactions in this matter to benefit the bank’s CRR position. Deutsche Bank lost money on its physical transactions on every day it traded at Silver Peak during the Relevant Period. On each of these 44 days, SPPC’s transmission charges and CAISO’s export charges, which were publicly available on the internet, exceeded Deutsche Bank’s revenue from the physical transactions. Further, Deutsche Bank’s scheduling of physical exports at Silver Peak raised prices at Silver Peak.

16. Deutsche Bank stipulates that during CAISO’s auction for March 2010 CRRs, it increased its CRR position at Silver Peak, increasing its exposure to losses from import congestion and gains from export congestion at Silver Peak.

17. Following calls from the CAISO Department of Market Monitoring expressing concerns regarding its trading at Silver Peak, Deutsche Bank stopped the Export Strategy as of trade date March 25, 2010. Enforcement determined that the Export Strategy increased the value of Deutsche Bank’s Silver Peak CRRs by approximately $172,645 during the Referral Period.5

18. Enforcement determined that, through the Export Strategy, Deutsche Bank engaged in cross-product manipulation, trading in one product (physical exports) with the intent to benefit a second product (the CRR position), and thereby violated the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2.6

5 This figure reflects further analysis since the issuance of the Order to Show Cause.

6 The Commission’s Anti-Manipulation Rule prohibits any entity from:

(1) using a fraudulent device, scheme or artifice, or making a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engaging in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; (3) in connection with a transaction subject to the jurisdiction of the Commission.

(continued…)
19. Enforcement determined that Deutsche Bank’s physical trades were not consistent with the fundamentals underlying the market price of Silver Peak, e.g., supply and demand, but rather were undertaken with the intent to change the value of CRRs. Deutsche Bank thus injected false and deceptive information into the marketplace and affected the price at Silver Peak, which hindered the proper functioning of the physical market at Silver Peak as well as the CRR market. By hindering the proper functioning of the CRR and physical markets, Deutsche Bank’s Export Strategy was a scheme that operated as a “fraud or deceit” under the Commission’s Anti-Manipulation Rule.

20. Enforcement concluded that Deutsche Bank’s CRR traders acted with the requisite manipulative intent because, among other reasons, they engaged in the physical transactions with the intent to increase the value of Deutsche Bank’s CRR position. Specifically, as stipulated by Deutsche Bank, the CRR traders sought for the exports at Silver Peak to change the price to benefit the bank’s losing CRR position. Deutsche Bank’s physical transactions were not profitable. Even if these physical transactions had been profitable, however, profitability is not determinative on the question of manipulation and does not inoculate trading from any potential manipulation claim (although profitability may be relevant in assessing the conduct). Rather, as we have recognized, the elements of manipulation are “determined by all the circumstances of a case.” Here, based on all the facts and circumstances, Enforcement determined that Deutsche Bank’s conduct constituted manipulation.

21. Enforcement also concluded that Deutsche Bank’s false designation of its physical trading as Wheeling-Through transactions to facilitate the Export Strategy also operated as a “fraud or deceit,” independently satisfying this element of the Commission’s Anti-Manipulation Rule.

22. Here, both Deutsche Bank’s physical energy and CRR transactions were jurisdictional transactions, which satisfies the jurisdictional element of the Anti-Manipulation Rule.

23. Enforcement determined that Deutsche Bank violated the Commission’s accuracy requirement, 18 C.F.R. § 35.41(b), which requires it to “provide accurate and factual information and not submit false or misleading information … in any communication.

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18 C.F.R. § 1c.2(a) (2012). Enforcement also determined that this conduct violated the similar provision of the CAISO Tariff, section 37.7.

with … independent system operators,” such as CAISO. Deutsche Bank violated these provisions by submitting false and fraudulent Wheeling-Through transactions to CAISO; these transactions did not meet the CAISO Tariff’s requirements for Wheeling-Through transactions because they did not have an external resource or load.

24. Deutsche Bank agrees to pay a civil penalty of $1,500,000; disgorge unjust profits of $172,645, plus interest; and implement improved compliance training and procedures.

III. Determination of the Appropriate Sanctions

25. In determining the appropriate remedy, Enforcement considered the factors described in section 316A(b) of the Federal Power Act and in the Revised Policy Statement on Penalty Guidelines. Enforcement concluded that: Deutsche Bank’s conduct undermined the proper functioning of the CAISO markets, that its conduct was committed with the knowledge of supervisory personnel, but that it and its employees cooperated in staff’s investigation. Enforcement concluded that Deutsche Bank did not have an effective compliance program. Despite the fact that the Deutsche Bank Compliance Handbook stated that “engaging in physical trading designed to benefit financial transactions” merited “heightened review” as potential manipulation, the trading personnel did not seek review of the Export Strategy.

26. The Commission concludes that the civil penalty, disgorgement of unjust profits, compliance training and procedures, and the compliance monitoring reports set forth in the Agreement are fair and equitable resolutions of the matters concerned and are in the public interest, as they reflect the nature and seriousness of Deutsche Bank’s conduct and recognize the company-specific considerations as stated above and in the attached Agreement.

27. The Commission directs CAISO to allocate the disgorged funds and interest for the benefit of the market participants harmed by Deutsche Bank’s conduct as determined by CAISO.

8 Enforcement also determined that this conduct violated the similar provision of the CAISO Tariff, section 37.5.

The Commission orders:

(A) The attached Stipulation and Consent Agreement is hereby approved without modification.

(B) This order terminates Docket No. IN12-4-000.

By the Commission.

( S E A L )

Kimberly D. Bose,
Secretary.
STIPULATION AND CONSENT AGREEMENT

I. Introduction

1. The staff of the Office of Enforcement (Enforcement) of the Federal Energy Regulatory Commission (Commission) and DB Energy Trading LLC (Deutsche Bank) enter into this Stipulation and Consent Agreement (Agreement) to resolve an investigation conducted under Part 1b of the Commission’s regulations, 18 C.F.R. Part 1b (2012). The investigation examined Deutsche Bank’s conduct in the markets of the California Independent System Operator Corporation (CAISO) related to the 17 MW Silver Peak intertie. Specifically, the investigation examined potential violations of the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2; of the Commission’s regulation prohibiting the submission of inaccurate information, 18 C.F.R. § 35.41(b); and of similar provisions of the CAISO tariff (Tariff) then in effect.\(^1\)

II. Stipulations

Enforcement and Deutsche Bank hereby stipulate and agree to the following facts:

2. Deutsche Bank has market-based rate authority. During the period here at issue, Deutsche Bank purchased and sold energy and Congestion Revenue Rights (CRRs) in the CAISO markets and purchased and sold both energy and financial transmission rights (FTRs) in other organized markets. In 2009 and 2010, Deutsche Bank was one of the largest participants in the CAISO CRR auction markets. Deutsche Bank’s trading in CRRs and FTRs was undertaken by traders on its FTR desk (the CRR traders). In the CAISO markets, these traders focused exclusively on bidding on CRRs and, until they undertook the trades at issue in this investigation, had no responsibility for physical trading.

3. Enforcement opened the investigation of Deutsche Bank following a June 15, 2010 referral by the CAISO Department of Market Monitoring (DMM) related to Deutsche Bank’s scheduling and trading practices in the CAISO markets for the period January 29, 2010 through March 24, 2010 (Referral Period) at the Silver Peak intertie.

4. Deutsche Bank had established a CRR position prior to the Referral Period. It entered the first quarter of 2010 holding a CRR position with an internal source and Silver Peak as a sink in the amount of 40.56 MW on-peak and 48.51 MW off-peak. Deutsche Bank added to this position in the monthly auction for January 2010 CRRs. As a result, Deutsche Bank had a net CRR position sinking at Silver Peak of 49.76 MW on-peak and 50.96 MW off-peak.

5. The capacity of the Silver Peak interties used in the CAISO-administered auction was 17 MW in both the import and export direction. CAISO is able to award CRRs that exceed the capacity in each direction when the net flow of all CRRs (including offsets via counter flow) awarded do not exceed the capacity of the line.

6. Both the on-peak and off-peak positions were “long;” they benefitted Deutsche Bank when export congestion occurred at Silver Peak and caused losses to Deutsche Bank when import congestion occurred at Silver Peak.

7. On January 15, 2010, CAISO derated the Silver Peak intertie. Instead of 17 MW in both directions, the derate allowed no net energy to flow in the import direction and limited the net flow to 13 MW in the export direction. The derate did not prevent bidding and scheduling in both directions because an export scheduled could be offset by imports.

8. Once the derate became effective on the trading day of January 19, 2010, Deutsche Bank began to lose money on its CRRs due to import congestion at Silver Peak.

9. On January 26, 2010, during CAISO’s auction for February 2010 CRRs, Deutsche Bank obtained CRRs that partially decreased its exposure to import congestion at Silver Peak. As a result of the auction, Deutsche Bank held a CRR position with Silver Peak as a sink in the amount of 31.44 MW on-peak and 39.14 MW off-peak. This position still left Deutsche Bank exposed to import congestion at Silver Peak.

10. Deutsche Bank’s CRR traders sought to offset Deutsche Bank’s remaining exposure by exporting physical energy at the Silver Peak intertie to eliminate the import congestion that was causing losses to its CRR positions. Given the derate of Silver Peak and Deutsche Bank’s long CRR position sinking at Silver Peak, Deutsche Bank’s scheduling of physical exports at Silver Peak raised prices at Silver Peak and caused its CRR position to gain value.

11. Deutsche Bank implemented its physical export strategy (Export Strategy) as of the January 29, 2010 trading day. Specifically, Deutsche Bank scheduled physical energy on transmission external to the CAISO system from Silver Peak to the Summit intertie and self-scheduled paired physical transactions consisting of exports (purchases) at Silver Peak and an equal amount of imports (sales) at Summit. When Deutsche Bank
executed the Silver Peak to Summit physical schedules, no import congestion appeared at Silver Peak and Deutsche Bank’s CRR position did not experience losses.

12. The physical transactions were at first scheduled as independent export and import transactions, but as Deutsche Bank continued to engage in such transactions the majority of the schedules were designated as Wheeling-Through transactions. Pairing export and import schedules as Wheeling-Through transactions ensures that CAISO either will schedule both flows or neither side of the transaction will flow; it would not cut one leg alone. Although the applicable CAISO tariff defined Wheeling-Through transaction as having both an external resource and an external load, Deutsche Bank’s physical transactions did not have either an external resource or an external load. Inside the CAISO, the Wheeling-Through designation led CAISO to conclude that Deutsche Bank was wheeling power from Summit to Silver Peak. Outside the CAISO, Deutsche Bank scheduled energy and transmission from the export point, Silver Peak, to the import point, Summit. When the transactions are taken together, there was no net outflow from or net inflow to CAISO.

13. Although for a handful of individual trading hours the physical transactions were profitable on a standalone basis, Deutsche Bank lost money on these physical transactions on every day it traded at Silver Peak. The transmission charges outside the CAISO and the CAISO’s export charges exceeded Deutsche Bank’s revenue from the physical transactions on each of these days.

14. For the period January 29 through February 20, 2010, Deutsche Bank scheduled 3 to 6 MW of exports at Silver Peak and imports at Summit. When the export transactions were executed, no import congestion occurred at Silver Peak and Deutsche Bank’s CRR positions did not experience losses. During this period, Deutsche Bank designated export-import pairs as Wheeling-Through transactions approximately 47% of the time with the remaining transactions scheduled as individual imports and exports.

15. On February 21, 2010, Deutsche Bank began scheduling 10 to 13 MW of exports at Silver Peak and designated 100% of these pairs as Wheeling-Through transactions. The traders continued to observe that no import congestion occurred when Deutsche Bank engaged in the physical transactions and that, for a small number of hours, there was export congestion that not only resulted in avoided losses but also increased the value of the CRR position.

16. On February 23, 2010, during CAISO’s auction for March 2010 CRRs, Deutsche Bank submitted bids to either increase or decrease the Silver Peak position depending on auction prices. The auction resulted in an increase in Deutsche Bank’s CRR position for March to 45.25 MW on-peak and 50.16 MW off-peak. As a result of the increased CRR position Deutsche Bank increased its exposure to losses from import congestion and gains from export congestion at Silver Peak.
17. On March 18, 2010, a CAISO client representative informed Deutsche Bank that the DMM wanted to discuss Deutsche Bank’s trading at Silver Peak. Conference calls were conducted on March 23 and March 26 during which the DMM raised concerns about Deutsche Bank’s transactions at Silver Peak. Deutsche Bank reduced its exports at Silver Peak to 3 MWs as of trade date March 20, 2010 and stopped scheduling exports at Silver Peak as of trade date March 25, 2010.

18. Enforcement determined that Deutsche Bank’s Export Strategy increased the value of its Silver Peak CRRs by approximately $172,645 during the Referral Period.

III. Violations

A. DBET Engaged in Market Manipulation

19. Based upon its investigation, Enforcement determined that, during the Referral Period, Deutsche Bank violated the Commission’s Anti-Manipulation Rule by engaging in transactions in one product, energy exports (physical purchases) at Silver Peak, with the intent to benefit a second product, its CRR position at Silver Peak. The Commission’s Anti-Manipulation Rule prohibits any entity from: (1) using a fraudulent device, scheme or artifice, or making a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engaging in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; (3) in connection with a transaction subject to the jurisdiction of the Commission.2

20. Enforcement determined Deutsche Bank’s Export Strategy violated the Commission’s Anti-Manipulation Rule.3 In a CRR market, the holder of a CRR is subject to various risks, including the risk that a derate will affect the value of the CRR. Through its Export Strategy, Deutsche Bank sought to negate the adverse impact the derate at Silver Peak had on the value of its CRR position. Deutsche Bank lost money consistently on its physical transactions. Its physical trades were not consistent with the fundamentals underlying the market price of Silver Peak, e.g., supply and demand, but rather were undertaken with the intent to change the value of CRRs. Deutsche Bank thus injected false and deceptive information into the marketplace and affected the price at Silver Peak, which hindered the proper functioning of the physical market at Silver Peak.

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3 Enforcement staff also determined that the conduct violated the similar section of then applicable CAISO Tariff, § 37.7 (2010).
as well as the CRR market. Enforcement determined that by hindering the proper functioning of the CRR and physical markets, which are both jurisdictional markets, Deutsche Bank’s Export Strategy was a scheme that operated as a “fraud or deceit” under the Commission’s Anti-Manipulation Rule.\(^4\)

21. Enforcement also concluded that Deutsche Bank’s designation of its physical trading as Wheeling-Through transactions to facilitate the Export Strategy also operated as a “fraud or deceit”\(^5\) because the designation was not accurate, as discussed below in section III.B.

### B. DBET Violated Accuracy Provisions

22. Further, Enforcement determined that Deutsche Bank violated the accuracy requirements of Commission regulations, 18 CFR § 35.41(b).\(^6\) Section 35.41(b) of the Commission’s regulations applies to Deutsche Bank, as a market-based rate seller. This section requires Deutsche Bank to “provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with… Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences.” In its Export Strategy, Deutsche Bank scheduled its exports at Silver Peak with imports of equal amount at the Summit intertie, designating the majority of the paired bids as Wheeling-Through transactions. Appendix A of the CAISO Tariff defines a “Wheeling-Through Transaction” as “the use of the CAISO Controlled Grid for the transmission of Energy from a resource located outside the CAISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating [Transmission Operator].”

23. Enforcement determined that Deutsche Bank did not meet the tariff’s requirements for Wheeling-Through transactions because its transactions lacked both an external resource and an external Load served, violating the Commission’s regulation requiring the submission of accurate schedules, 18 CFR § 35.41(b), and the identical provision of the CAISO Tariff.

### IV. Remedies and Sanctions

24. For purposes of settling any and all civil and administrative disputes arising out of, related to, or connected with Enforcement’s investigation, Deutsche Bank agrees with

\(^4\) 18 C.F.R. § 1c.2(a)(3) (2012).

\(^5\) Id.

\(^6\) Enforcement staff also determined that the conduct violated the similar section of then applicable CAISO Tariff, § 37.5.1 (2010).
the facts as stipulated in Section II of this Agreement but neither admits nor denies the violations described in Section III of this Agreement. Deutsche Bank agrees to take the following actions.

A. Civil Penalty

25. Deutsche Bank shall pay a civil penalty of $1,500,000 to the United States Treasury, by wire transfer, within ten days after the Effective Date of this Agreement, as defined below.

B. Disgorgement

26. Deutsche Bank shall disgorge unjust profits of $172,645 resulting from its Export Strategy, plus interest, to CAISO within ten days after the Effective Date of this Agreement as defined below, for distribution to market participants affected by Deutsche Bank’s actions.

C. Compliance

27. To the extent not already implemented since the Referral Period, Deutsche Bank shall adopt compliance measures and procedures related to its trading of jurisdictional products, including CRRs and other FTRs, to the extent that it continues to trade in jurisdictional products. These measures shall include improved training for its traders, supervisors, and managers regarding the Commission’s regulations governing energy trading, including the adherence to the tariffs in the organized markets in which Deutsche Bank participates. Deutsche Bank shall make an initial compliance monitoring report and thereafter shall make semi-annual compliance monitoring reports to Enforcement for one year following the Effective Date of this Agreement. The initial compliance monitoring report shall be submitted no later than 60 days after the Effective Date of this Agreement. The period covered by the initial compliance monitoring report shall be March 26, 2010, through the Effective Date of this Agreement. The first semi-annual compliance monitoring report shall be submitted no later than ten days after the end of the second calendar quarter after the quarter in which the Effective Date of this Agreement falls. The period covered by the report shall consist of the six months ending one calendar month prior to the date of such report. The second semi-annual compliance monitoring report shall be submitted six months thereafter for the six month period succeeding the prior reporting period. Provided, however, that the foregoing compliance measures and procedures shall not be required to address specific products or markets if, as certified in its compliance monitoring reports, Deutsche Bank no longer transacts in those products or markets and does not resume transacting in those products or markets within one year after the Effective Date of this Agreement.
28. Each compliance monitoring report shall: (1) advise Enforcement of any violations of Commission regulations or the CAISO tariff requirements that have occurred during the applicable period and are known to Deutsche Bank either as a result of its monitoring and testing programs or otherwise; (2) provide a detailed update of all compliance measures and procedures instituted, and compliance training administered, by Deutsche Bank in the applicable period, including a description of the compliance measures and procedures instituted, the compliance training provided to all relevant personnel concerning the CAISO Tariff, and a statement of the personnel or other evidence demonstrating that the personnel have received such training and when the training took place; and (3) include an affidavit executed by an officer of Deutsche Bank that the compliance monitoring reports are true and accurate to the best of his or her knowledge. Upon request by Enforcement, Deutsche Bank shall provide to Enforcement documentation to support its reports. After the receipt of the second semi-annual report, Enforcement may, at its sole discretion, require Deutsche Bank to submit semi-annual reports for one additional year.

V. Terms

29. The Effective Date of this Agreement shall be the date on which the Commission issues an order approving this Agreement without material modification. When effective, this Agreement shall resolve the matters specifically addressed herein as to Deutsche Bank and any affiliated entity, and their agents, officers, directors and employees, both past and present, and any successor in interest to Deutsche Bank.

30. Commission approval of this Agreement in its entirety and without material modification shall release Deutsche Bank and forever bar the Commission from holding Deutsche Bank, its affiliates, agents, officers, directors and employees, both past and present, liable for any and all administrative or civil claims arising out of, related to, or connected with the investigation addressed in this Agreement.

31. Deutsche Bank’s failure to: (a) make a timely civil penalty payment; (b) make a timely disgorgement payment to CAISO; (c) comply with the compliance monitoring requirement specified herein; or (d) comply with any other provision of this Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act, 16 U.S.C. § 792, et seq., and may subject Deutsche Bank to additional action under the enforcement and penalty provisions of the Federal Power Act.

32. If Deutsche Bank fails to make the civil penalty and disgorgement payments described above at the times agreed by the parties, interest payable to the United States Treasury will begin to accrue pursuant to the Commission’s regulations at 18 C.F.R. § 35.19(a)(2)(iii)(A) (2012) from the date the payments are due, in addition to any other enforcement action and penalty that the Commission may take or impose.
33. This Agreement binds Deutsche Bank and its agents, successors, and assigns. The Agreement does not create any additional or independent obligations on Deutsche Bank, or any affiliated entity, its agents, officers, directors, or employees, other than the obligations identified in this Agreement.

34. The signatories to this Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer, or promise of any kind by any member, employee, officer, director, agent, or representative of Enforcement or Deutsche Bank has been made to induce the signatories or any other party to enter into the Agreement.

35. Unless the Commission issues an order approving this Agreement in its entirety and without material modification, the Agreement shall be null and void and of no effect whatsoever, and neither Enforcement nor Deutsche Bank shall be bound by any provision or term of this Agreement, unless otherwise agreed to in writing by Enforcement and Deutsche Bank.

36. In connection with the payment of the civil penalty provided for herein, Deutsche Bank agrees that the Commission’s order approving this Agreement without material modification shall be a final and unappealable order assessing a civil penalty under § 316A(b) of the Federal Power Act, 16 U.S.C. § 825o-1(b). Deutsche Bank waives findings of fact and conclusions of law, rehearing of any Commission order approving this Agreement without material modification, and judicial review by any court of any Commission order approving this Agreement without material modification.

37. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity, and accepts this Agreement on the entity’s behalf.
38. The undersigned representative of Deutsche Bank affirms that he or she has read this Agreement, that all of the matters set forth in the Agreement are true and correct to the best of his or her knowledge, information, and belief that he or she understands that this Agreement is entered into by Enforcement in express reliance on those representations, and that he or she has had the opportunity to consult with counsel.

39. This Agreement may be signed in counterparts.

Agreed to and Accepted:

Norman Bay  
Director, Office of Enforcement  
Federal Energy Regulatory Commission  
Date: Jan. 14, 2013

Hank Jones  
Managing Director  
DB Energy Trading LLC  
Date: 11/4/13

Carolyynn Pereyra  
Vice President and Counsel  
DB Energy Trading LLC  
Date: 11/14/2013
ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued November 19, 2012)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) between the Office of Enforcement (Enforcement) and Gila River Power, LLC (Gila River). This order is in the public interest because it resolves Enforcement’s investigation under Part 1b of the Commission’s regulations, 18 C.F.R. Part 1b (2012), into Gila River’s conduct in the markets of the California Independent System Operator Corporation (CAISO). The investigation examined possible violations of the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2; of the Commission’s regulation prohibiting the submission of inaccurate information, 18 C.F.R. § 35.41(b); and of the similar provisions of the CAISO tariff.\(^1\) Gila River admitted the violations and agreed to pay a civil penalty of $2,500,000, pay disgorgement of $911,553, plus interest, and undertake improved compliance training and procedures.

I. BACKGROUND

2. As described in the Agreement, Gila River is an indirect, wholly-owned subsidiary of Entegra Power Group LLC. Gila River has market-based rate authority\(^2\) and purchases and sells energy in the western markets and the CAISO markets. During the relevant

\(^1\) CAISO Fourth Replacement Tariff, Conformed Fourth Replacement CAISO Tariff (Tariff), § 37.5.1 (accuracy) and § 37.7 (manipulation).

time period, Gila River owned and operated the entire 2,200 MW Gila River plant located southwest of Phoenix, Arizona, which consists of four 550 MW power blocks. For the period investigated, July 2009 through October 2010 (Relevant Period), three of those four blocks, or approximately 1,300-1,600 MW, were available for trading and reserve-sharing commitments.

3. Gila River sold power generated from its Gila River plant into the CAISO markets. Gila River often could obtain a better price for its power in the CAISO markets than in the rest of the western markets. When selling power into the CAISO markets, Gila River preferred to sell the power at the Palo Verde intertie because the cost of transmission from its plant to Palo Verde was less than the cost of transmission to other interties. But, Palo Verde was often congested in the import direction, which limited the amount of power that Gila River could import at Palo Verde and lowered the price for imports there. During the Relevant Period, Gila River imported approximately 350 to 3,000 MWhs per day into the CAISO at the Palo Verde intertie.

II. INVESTIGATION

4. Following a referral by the CAISO Department of Market Monitoring, Enforcement opened a non-public, preliminary investigation of Gila River to determine whether it violated the Commission’s regulations and the CAISO Tariff.

III. STIPULATION AND CONSENT AGREEMENT

5. As admitted by Gila River and described in the Agreement, during the Relevant Period, Gila River engaged in two strategies in the CAISO markets, the “Standalone Wheel” strategy and the “Adjustment Wheel” strategy. To further each strategy, Gila River submitted transactions designated as Wheeling-Through transactions. The use of the Wheeling-Through designation indicates to the CAISO that the Scheduling Coordinator is wheeling power through California from the linked import point to the linked export point. The Tariff required a Wheeling-Through transaction to have a resource outside of CAISO and a Load outside of CAISO.3 Gila River, however, was not wheeling power and lacked a resource or a Load outside the CAISO with respect to these Wheeling-Through transactions.

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3 Tariff, § 30.5.4 (incorporating definition of Wheeling-Through); Tariff Appendix A, Master Definitions Supplement (defining Wheeling-Through); see also Tariff, § 1.2 (“Capitalized terms used in this CAISO Tariff shall have the meanings set forth in the Master Definitions Supplement.”).
A. The Standalone Wheel Strategy

6. In the Standalone Wheel strategy, Gila River scheduled its Wheeling-Through transaction inside the CAISO from an uncongested node as an import (sale) to a node congested in the import direction as an export (purchase), usually Palo Verde. Outside the CAISO, Gila River scheduled energy and transmission from the export point to the import point, forming a circular schedule. Gila River did not use a resource outside the CAISO to supply its imports nor did it have Load outside the CAISO as a destination for its exports. As a result of these transactions, on a net basis, no additional power flowed into or out of the CAISO.

7. Gila River engaged in the Standalone Wheel strategy from July 22, 2009 through March 16, 2010 and made approximately $613,801 in profits from the strategy.

B. The Adjustment Wheel Strategy

8. Gila River imported power from its Gila River plant into the CAISO primarily at Palo Verde. Import congestion at Palo Verde or other congested points would lower the price there and thereby reduce the amount of power Gila River could import into the CAISO. In the Adjustment Wheel strategy, Gila River used Wheeling-Through transactions in the Day Ahead market to increase the amount of power it could import into the CAISO and to increase the price paid for its imports.

9. In the Adjustment Wheel strategy, the Wheeling-Through transactions: a) helped Gila River to avoid creating congestion at a point; b) which raised the price at that point relative to what the price would have been had Gila River sought to import more energy at that point; c) which in turn benefitted any remaining concurrent imports from Gila River that were priced at that same point. In the Day-Ahead market, Gila River submitted simultaneously, a Wheeling-Through bid and a bid to import energy from the Gila River plant into the CAISO at the same intertie that served as the export point of the Wheeling-Through bid, usually Palo Verde.

10. After the Day-Ahead market settled, Gila River entered its bids in the Hour Ahead Scheduling Process market: it redirected its imports so that the maximum quantity flowed to its preferred, but otherwise congested, import point, e.g., Palo Verde, without causing congestion and so that any remaining imports flowed to the point designated as the import leg of the Adjustment Wheel. At the same time, Gila River bought back the import and export legs of the Adjustment Wheel, in effect cancelling out the Adjustment Wheel.

11. Gila River engaged in the Adjustment Wheel strategy during the entire Relevant Period, i.e., from July 2009 through October 2010, and made approximately $296,753 in profits from this strategy.
C. Violations

12. Gila River admits that it violated 18 C.F.R. § 35.41(b) of the Commission’s regulations. This regulation requires a market-based rate seller, such as Gila River, to provide accurate and factual information and prohibits such sellers from submitting false or misleading information or omitting material information in any communication with, among others, independent system operators, such as the CAISO. Gila River violated these provisions by submitting Wheeling-Through transactions that did not meet the Tariff’s requirements for Wheeling-Through transactions. The Tariff required that a Wheeling-Through transaction have both a resource and a Load outside the CAISO. For both the Standalone Wheel strategy and the Adjustment Wheel strategy, Gila River’s Wheeling-Through transactions had neither.

13. Gila River admits that it violated the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2 in undertaking the Adjustment Wheel strategy. The Commission’s Anti-Manipulation Rule prohibits any entity from: (1) using a fraudulent device, scheme or artifice, or making a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engaging in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; (3) in connection with a transaction subject to the jurisdiction of the Commission. Gila River’s conduct constituted fraud in two ways: its submission of inaccurate Wheeling-Through transactions constituted fraud and its submission of these transactions to benefit its concurrent imports from the Gila River plant constituted fraud. Gila River’s trader acted with the requisite scienter as established by his admission that he submitted Wheeling-Through transactions to increase the price at Palo Verde and the value of Gila River’s imports there. Gila River’s Wheeling-Through transactions and its imports were jurisdictional.

4 Gila River also admits that it violated the similar provision of § 37.5 of the CAISO Tariff.

5 Tariff, § 30.5.4 (incorporating definition of Wheeling-Through); Tariff Appendix A, Master Definitions Supplement (defining Wheeling-Through); see also Tariff, § 1.2 (“Capitalized terms used in this CAISO Tariff shall have the meanings set forth in the Master Definitions Supplement.”).

6 Gila River also admits that it violated the similar provision of the CAISO Tariff, § 37.7.

7 18 C.F.R. § 1c.2(a) (2012).
IV. **DETERMINATION OF THE APPROPRIATE CIVIL PENALTY**

14. Gila River agrees to pay a civil penalty of $2,500,000, to disgorge $910,553 in unjust profits, plus interest, and to make a compliance report to Enforcement.

15. In determining the appropriate remedy, Enforcement considered the factors described in section 316A(b) of the Federal Power Act and in the Revised Policy Statement on Penalty Guidelines. Enforcement considered that: Gila River’s conduct was serious and was committed intentionally; that its conduct undermined the proper functioning of the CASIO markets; and that its conduct was committed with the knowledge of supervisory personnel.

16. Enforcement also considered that Gila River and its employees provided exemplary cooperation in the investigation and were productive and diligent in assisting staff at all phases of its investigation. Further, Gila River’s cooperation made staff’s fact-finding efficient and productive and thereby helped conserve Commission resources.

17. The Commission concludes that the civil penalty, disgorgement, compliance measures and the compliance monitoring reports set forth in the Agreement are fair and equitable resolutions of the matters concerned and are in the public interest, as they reflect the nature and seriousness of Gila River’s conduct. The Commission also concludes that the civil penalty is consistent with the Revised Policy Statement on Penalty Guidelines.

18. The Commission directs the CAISO to allocate the disgorged funds and interest for the benefit of electric ratepayers. The CAISO may allocate such funds in its discretion, including directing the funds to those harmed by the conduct at issue or augmenting efforts to monitor market participant behavior and to attempt to prevent future misconduct.

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9 *Id.*
The Commission orders:

The attached Stipulation and Consent Agreement is hereby approved without modification.

By the Commission.

( S E A L )

Kimberly D. Bose,
Secretary.
STIPULATION AND CONSENT AGREEMENT

I. INTRODUCTION

1. The staff of the Office of Enforcement (Enforcement) of the Federal Energy Regulatory Commission and Gila River Power LLC (Gila River) enter into this Stipulation and Consent Agreement (Agreement) to resolve an investigation conducted under Part 1b of the Commission’s regulations, 18 C.F.R. Part 1b (2012). The investigation examined Gila River’s conduct in the markets of the California Independent System Operator Corporation (CAISO). Specifically, the investigation examined potential violations of the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2; of the Commission’s regulation prohibiting the submission of inaccurate information, 18 C.F.R. § 35.41(b); and of similar provisions of the CAISO Tariff.¹

II. STIPULATIONS

Enforcement and Gila River hereby stipulate and agree to the following facts:

2. Gila River is an indirect, wholly-owned subsidiary of Entegra Power Group LLC. Gila River has market-based rate authority and purchases and sells energy in the western markets and the CAISO markets. During the relevant time period, Gila River owned and operated the entire 2,200 MW Gila River plant located southwest of Phoenix, Arizona, which consists of four 550 MW power blocks.² For the period investigated, July 2009 through October 2010 (Relevant Period), three of those four blocks, or approximately 1,300-1,600 MW, were available for trading and reserve-sharing commitments.

¹ CAISO Fourth Replacement Tariff, Conformed Fourth Replacement CAISO Tariff (Tariff), §§ 37.5.1 (accuracy) and 37.7 (manipulation). Capitalized terms herein have the meaning set forth in the Tariff.

² Gila River subsequently sold two of the power blocks to a non-affiliated party.
3. Enforcement opened the investigation of Gila River following an October 6, 2010 referral by the CAISO Department of Market Monitoring (DMM) related to Gila River’s scheduling and trading practices in the CAISO markets. Gila River and its employees provided exemplary cooperation and were productive and diligent in assisting Enforcement in all phases of the investigation. Its employees were candid and forthcoming in their testimony and in meetings with Enforcement, and Enforcement found them genuinely contrite. Gila River was transparent regarding its conduct, which made Enforcement’s fact-finding efficient and productive and helped conserve staff’s resources. Together with its attorneys, Gila River employees worked with Enforcement staff to bring to light salient facts and to develop a sound method to analyze and calculate Gila River’s profits from its conduct. In agreeing to a penalty amount, Enforcement favorably considered this conduct of Gila River and its employees.

4. Gila River sold power generated from its Gila River plant into the CAISO markets. Gila River often could obtain a better price for its power in the CAISO markets than in the rest of the western markets. Gila River preferred to sell the power at the Palo Verde intertie because the cost of transmission from its plant to Palo Verde was less than the cost of transmission to other interties. Palo Verde was often congested in the import direction, however, this congestion limited the amount of power that Gila River could import at Palo Verde and lowered the price for imports there. During the Relevant Period, Gila River imported from approximately 350 to 3,000 MWhs per day into the CAISO at the Palo Verde intertie.

5. During the Relevant Period, Gila River engaged in two strategies in the CAISO markets, the “Standalone Wheel” strategy and the “Adjustment Wheel” strategy. To further each strategy, Gila River submitted transactions designated as Wheeling Through transactions. A Wheeling Through transaction consists of an export bid and an import bid that are linked such that both of them will clear in the CAISO market or neither of them will clear. The use of the Wheeling Through designation indicates to the CAISO that the Scheduling Coordinator is wheeling power through California from the linked import point to the linked export point. The Tariff requires a Wheeling Through transaction to have a resource outside of CAISO and a Load outside of CAISO. Gila River, however, lacked a resource or a Load outside the CAISO with respect to these Wheeling Through transactions. Even though it was not wheeling power through

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3 Tariff, § 30.5.4 (incorporating definition of Wheeling Through); Tariff Appendix A, Master Definitions Supplement (defining Wheeling Through); see also Tariff, § 1.2 (“Capitalized terms used in this CAISO Tariff shall have the meanings set forth in the Master Definitions Supplement.”).
CAISO, Gila River submitted its bids as Wheeling Through bids throughout the Relevant Period as part of one or both of the strategies.

A. The Standalone Wheel Strategy

6. In the Standalone Wheel strategy, Gila River scheduled its Wheeling Through transactions inside the CAISO from an uncongested node as an import (sale) to a node congested in the import direction as an export (purchase), usually Palo Verde. Outside the CAISO, Gila River scheduled energy and transmission from the export point to the import point, forming a circular schedule. Gila River did not use a resource outside the CAISO nor did it have Load outside the CAISO for its Wheeling Through transactions. As a result of these transactions, on a net basis, no additional power flowed into or out of the CAISO.

7. In the Standalone Wheel strategy, Gila River profited from the Wheeling Through transactions because it was awarded the bid only when the price at the import node (sale) was greater than the price at the export node (purchase) and because it bid a spread great enough to cover its costs, such as transmission costs outside the CAISO and CAISO export fees. Gila River engaged the Standalone Wheel strategy from July 22, 2009 through March 16, 2010 and made approximately $613,801 in profits from the strategy.

B. The Adjustment Wheel Strategy

8. Gila River imported power into the CAISO primarily at Palo Verde. Import congestion at Palo Verde or other congested points would lower the price there and thereby reduce Gila River’s revenues for imports sourced from the Gila River plant. To prevent import congestion and avoid these effects, Gila River developed the Adjustment Wheel strategy. In the Adjustment Wheel strategy, Gila River used Wheeling Through transactions in the Day Ahead market to increase the amount of power it could import into the CAISO and to increase the price paid for those imports. Through the strategy, Gila River also learned whether some import nodes were less congested than others. Gila River used this information to redirect its imports from its normally preferred import nodes to less congested nodes.

9. In the Adjustment Wheel strategy, the Wheeling Through transactions: (a) helped Gila River to avoid creating congestion at a point; (b) which raised the price at that point relative to what the price would have been had Gila River sought to import more energy at that point; (c) which in turn benefitted any remaining concurrent imports from Gila River that were priced at that same point. Specifically, in the Day-Ahead Market, Gila River submitted a Wheeling Through bid which linked an export at an intertie that was typically congested in the import direction, usually Palo Verde, to an import at another intertie that was typically not congested (Adjustment Wheel). As the trader who
developed the strategy wrote at the time, Gila River was “[u]sing wheels as a way to prop up one LMP that gets congested by linking it to another point that doesn’t get congested.” The export bid leg of the Adjustment Wheel relieved import congestion at the export point, usually Palo Verde, which increased the price there.

10. Simultaneously, Gila River submitted a bid to import energy from the Gila River plant into the CAISO at the same intertie that served as the export point of the Adjustment Wheel, again usually Palo Verde. The price increase benefitted Gila River’s imports at that same point. The trader in charge of the strategy described the benefits this way: “The upside here is that most of these times I’m importing hundreds at PV [Palo Verde] and my wheel has raised the price for PV for all the power I’m importing, [i.e., power sourced from the Gila River plant].”

11. Because the export bid leg of Adjustment Wheel provided counterflow to the import bid from the Gila River plant, the Adjustment Wheel relieved the congestion that Gila River’s imports otherwise would have caused at the import point, e.g., Palo Verde.

12. After the Day-Ahead market settled, Gila River entered its bids in the Hour Ahead Scheduling Process market: it redirected its imports so that the maximum quantity flowed to its normally preferred, but otherwise congested point, e.g., Palo Verde, without causing congestion and so that any remaining imports flowed to the point designated as the import leg of the Adjustment Wheel. At the same time, Gila River bought back the import and export legs of the Adjustment Wheel, in effect cancelling out the Adjustment Wheel.

13. Gila River engaged in the Adjustment Wheel strategy during the entire Relevant Period, i.e., from July 2009 through October 2010, and made approximately $296,753 in profits from this strategy.

III. Violations

A. Gila River Violated Accuracy Provisions

14. Gila River violated the accuracy requirements of Commission regulations, 18 C.F.R. § 35.41(b), and of the similar CAISO Tariff § 37.5. Section 35.41(b) of the Commission’s regulations applies to Gila River as a market-based rate seller. This section requires Gila River to:

provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with … Commission-approved regional transmission organizations, Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence
to prevent such occurrences.

Section 37.5 of the CAISO Tariff is similar.

15. During the Relevant Period, Gila River submitted schedules to the CAISO that included Wheeling Through transactions as part of both its Standalone Wheel strategy and its Adjustment Wheel strategy. Appendix A of the Tariff defines a “Wheeling Through Transaction” as “the use of the CAISO Controlled Grid for the transmission of Energy from a resource located outside the CAISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating [Transmission Operator].” Although Gila River’s employees claimed that they were uncertain about whether its Wheeling Through bids complied with the Tariff, Gila River’s employees, the trader and his supervisors, chose to proceed with these transactions without conducting a sufficient review of the Tariff or seeking guidance from Gila River’s legal or compliance staff.

16. Gila River admits that it did not meet the Tariff’s requirements for Wheeling Through transactions because it was not wheeling power through CAISO and its transactions lacked both a resource and a Load outside the CAISO, and admits that it violated the Commission’s regulation requiring the submission of accurate schedules, 18 C.F.R. § 35.41(b), and the similar provision of the Tariff, § 37.5.

B. Gila River Engaged in Market Manipulation

17. During the Relevant Period, Gila River’s use of the Adjustment Wheel strategy violated the Commission’s Anti-Manipulation Rule by improperly using Wheeling Through transactions to trade in one instrument, energy exports (purchases) at a point congested in the import direction, with the intent to benefit a second instrument, its imports sourced from the Gila River plant and imported (sold) at the same point. The Commission’s Anti-Manipulation Rule prohibits any entity from: (1) using a fraudulent device, scheme or artifice, or making a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engaging in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; (3) in connection with a transaction subject to the jurisdiction of the Commission.\(^4\)

18. The foregoing facts establish that Gila River violated the Commission’s Anti-Manipulation Rule. Gila River’s designation of its trades as Wheeling Through

\(^4\) 18 C.F.R. § 1c.2(a)(3).
transactions to facilitate its Adjustment Wheel strategy operated as a fraud or deceit because the transactions were falsely designated, as discussed above.

19. Further, in its Adjustment Wheel strategy, Gila River moved the price at the congested node, primarily Palo Verde, compared to what it would have been had Gila River tried to import energy at the congested node. Gila River’s Wheeling Through transactions done in conjunction with its Adjustment Wheel strategy were undertaken with the intent to increase the revenues for its imports sourced from the Gila River plant and were not based on market fundamentals. Gila River also injected false and deceptive information into the marketplace through its designation of its import and export bids as Wheeling Through transactions. These actions undermined the proper functioning of the CAISO markets and operated as a fraud or deceit under the Commission’s Anti-Manipulation Rule.

20. In the Adjustment Wheel strategy, Gila River’s trader admitted that he submitted the Wheeling Through transactions in order to increase the price at Palo Verde when there was congestion there to increase revenues paid for Gila River’s imports sourced from the Gila River plant. Contemporaneous documents confirmed this intent.

21. Gila River’s Wheeling Through transactions as well as its imports sourced from the Gila River plant were jurisdictional transactions.

22. Gila River admits that, for the reasons stated above, it violated the Commission’s Anti-Manipulation Rule, 18 C.F.R. § 1c.2 and the similar provision of the Tariff, § 37.7.

IV. REMEDIES AND SANCTIONS

23. For purposes of settling any and all civil and administrative disputes arising from Enforcement’s investigation, Gila River agrees with the facts as stipulated in Section II of this Agreement and admits to the violation of the Commission’s Accuracy requirements and of the identical violation of the CAISO Tariff set forth in Section III.A of this Agreement and of the Commission’s Anti-Manipulation Rule and the identical provision of the CAISO Tariff, described in Section III.B of this Agreement. Gila River agrees to take the following actions.

A. Civil Penalty

24. Gila River shall pay a civil penalty of $2.5 million to the United States Treasury, by wire transfer, within ten days after the Effective Date of this Agreement, as defined below.
B. Disgorgement

25. Within ten days after the Effective Date of this Agreement as defined below, Gila River shall disgorge unjust profits of $910,553, plus interest (accrued consistent with 18 C.F.R. § 35.19a(a)(2)), to the CAISO to use or distribute in its discretion for the benefit of electric ratepayers.

C. Compliance

26. Gila River shall adopt compliance measures and procedures related to its trading of jurisdictional products. These measures shall include improved training for its traders, supervisors, and managers regarding the Commission’s regulations governing energy trading, including the adherence to the tariffs in the organized markets in which Gila River participates. Gila River shall make an initial compliance monitoring report and thereafter shall make semi-annual compliance monitoring reports to Enforcement for one year following the Effective Date of this Agreement. The initial compliance monitoring report shall be submitted no later than 60 days after the Effective Date of this Agreement. The period covered by the initial compliance monitoring report shall be October 12, 2010, through the Effective Date of this Agreement. The first semi-annual compliance monitoring report shall be submitted no later than ten days after the end of the second calendar quarter of 2013 and shall cover the period from the Effective Date until the end of the second calendar quarter of 2013. The second semi-annual compliance monitoring report shall be submitted six months thereafter for the third and fourth calendar quarters of 2013.

27. Each compliance monitoring report shall: (a) advise Enforcement whether violations of Commission regulations or Tariff requirements have occurred during the applicable period; (b) provide a detailed update of all compliance measures and procedures instituted, and compliance training administered, by Gila River in the applicable period, including a description of the compliance measures and procedures instituted, the compliance training provided to all relevant personnel concerning the Tariff, and a statement of the personnel or other evidence demonstrating that the personnel have received such training and when the training took place; and (c) include an affidavit executed by an officer of Gila River that the compliance monitoring reports are true and accurate. Upon request by Enforcement, Gila River shall provide to Enforcement documentation to support its reports. After the receipt of the second semi-annual report, Enforcement may, at its sole discretion, require Gila River to submit semi-annual reports for one additional year.
V. TERMS

28. The Effective Date of this Agreement shall be the date on which the Commission issues an order approving this Agreement without material modification and that order becomes no longer subject to appeal. When effective, this Agreement shall resolve the matters specifically addressed herein as to Gila River and any affiliated entity, and their agents, officers, directors and employees, both past and present, and any successor in interest to Gila River.

29. Commission approval of this Agreement in its entirety and without material modification shall release Gila River and forever bar the Commission from holding Gila River, its affiliates, agents, officers, directors and employees, both past and present, liable for any and all administrative or civil claims arising out of, related to, or connected with the investigation addressed in this Agreement.

30. Gila River’s failure to: (a) make a timely civil penalty payment; (b) make a timely disgorgement payment to CAISO; (c) comply with the compliance monitoring requirement specified herein; or (d) comply with any other provision of this Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act, 16 U.S.C. § 792, et seq., and may subject Gila River to additional action under the enforcement and penalty provisions of the Federal Power Act.

31. If Gila River fails to make the civil penalty and disgorgement payments described above at the times agreed by the parties, interest payable to the United States Treasury will begin to accrue pursuant to the Commission’s regulations at 18 C.F.R. § 35.19a(a)(2)(iii)(A) from the date the payments are due, in addition to any other enforcement action and penalty that the Commission may take or impose.

32. This Agreement binds Gila River and its agents, successors, and assigns. The Agreement does not create any additional or independent obligations on Gila River, or any affiliated entity, its agents, officers, directors, or employees, other than the obligations identified in this Agreement. Enforcement and Gila River do not intend for this Agreement to entitle any other party to any claim or right of any kind, it being the intent of the Enforcement and Gila River that this Agreement shall not be construed as a third-party beneficiary contract.

33. The signatories to this Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer, or promise of any kind by any member, employee, officer, director, agent, or representative of Enforcement or Gila River has been made to induce the signatories or any other party to enter into the Agreement.
34. Unless the Commission issues an order approving this Agreement in its entirety and without material modification, the Agreement shall be null and void and of no effect whatsoever, and neither Enforcement nor Gila River shall be bound by any provision or term of this Agreement, unless otherwise agreed to in writing by Enforcement and Gila River.

35. In connection with the payment of the civil penalty provided for herein, Gila River agrees that the Commission’s order approving this Agreement without material modification shall be a final and unappealable order assessing a civil penalty under § 316A(b) of the Federal Power Act, 16 U.S.C. § 825o-1(b). Gila River waives findings of fact and conclusions of law, rehearing of any Commission order approving this Agreement without material modification, and judicial review by any court of any Commission order approving this Agreement without material modification.

36. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity, and accepts this Agreement on the entity’s behalf.

37. The undersigned representative of Gila River affirms that he or she has read this Agreement, that all of the matters set forth in the Agreement are true and correct to the best of his knowledge, information and belief, that he understands that this Agreement is entered into by Enforcement in express reliance on those representations, and that he or she has had the opportunity to consult with counsel.

38. This Agreement may be executed in duplicate, each of which so executed shall be deemed to be an original.

39. Agreed to and Accepted:

Norman Bay  
Director, Office of Enforcement  
Federal Energy Regulatory Commission  
Date: 11/13/12

Jerry Coffey  
General Counsel  
Gila River Power LLC  
Date: 11/12/12
Natural Gas Pipelines and the Demands of the Electric Industry

EBA Northeast Chapter Annual Meeting
June 5, 2013
Gas & Electric Observations

Challenges and Mounting Pressures in New England Region

NE EBA Chapter Annual Meeting June 5, 2013

John P. Rudiak
Connecticut Natural Gas and Southern Connecticut Gas

- Overview of New England Region
- LDC Perspective – Gas and Electric Issues
- Challenges and Mounting Pressures
- Remaining Questions
Overview of the New England Region

Access to Supply

- Existing low cost Marcellus production as close as 200-300 miles from New England
- West to east pipeline flows at capacity most of winter- only firm accessing the low cost supplies
- Major bottlenecks will remain

Market Conditions

- Wellhead prices (i.e. Marcellus shale) low and stable
- New England city gate prices sustained at high levels and volatile
  - Imbedded transport values much higher than capacity cost (including new construction incremental)
  - Secondary market participants (electric market) are paying higher prices than firm primary (including new construction costs) and experiencing diminishing reliability and flexibility
- Gas LDC portfolios use primary firm from wellhead and storage fields, on-system peaking, not dependent on secondary market

Electric market design has driven dependency on secondary gas services

Natural Gas Market Overview

Infrastructure Bottlenecks

NUMEROUS PIPELINE EXPANSIONS UPSTREAM OF BOTTLENECKS TO MOVE MARCELLUS SHALE GAS BACKWARDS AND SIDEWAYS BUT none add capacity to New England

Sources and Notes: Original Map — NGA, Restriction points per pipeline flow restriction notices
Secondary market imbedded capacity values are higher than gas capacity costs

- Currently observed secondary market values in New England are over 2X annualized historical rates & new project indications

City gate gas prices and basis sustained at high levels throughout winter
Net Deliveries into the East-End of the New England Pipeline Lower

*Schedule pipeline volumes on TGP & AGT at Salem, Everett and Dracut meters – per pipeline EBB

Objectives
- Preservation of reliability to LDC customers
- Avoid cost subsidization by gas customers
- Ensure ability to serve growing markets
- Work proactively to mutually beneficial solutions

Efforts
- Help to fill communication gap
- Convey the urgency of the situation
- Contribute ideas and solutions
- Work jointly with gas pipelines and importers to assist in solutions

Consensus LDC Views to Date
- Communication and scheduling/coordination already nearly fully leveraged
- Clearly an physical infrastructure issue
- Electric market design discouraging long term primary contracting
- Embracing gas market structure and culture more than ever
  - Spirit of cooperation, ability to work together, settle issues, get things done
  - Ability to get infrastructure built
Regional Efforts - Among Others

**NE Gas/Electric Focus Group**
- Established post August 20, 2012 FERC Technical Conference
- Broad stakeholders, but has no authority
- States and regulators in a lead role through NESCOE
  - Independent analysis by Black and Veatch - extremely timely and helpful to process
- Primary vehicle where gas industry is participating
- Separate from NEPOOL and ISO-NE long standing processes
- Helping to fill clear communication gap - exchange of facts and information
- Common themes developed
- List of solutions
  - Gas industry developed list of short, mid and long term solutions
  - Other solutions and ideas presented
- Last winter experience shifted focus to winter 2013/2014 ideas
- Group will issue report on challenges and solution categories

Challenges Persist in Finding Solutions……

**Identification of Problem**
Differing opinions on existence of a problem
Disagreement on what root cause

**Analysis of Problem**
Unsure how to analyze or perform enough detail in analysis to be meaningful
Lack of consistent interpretation of analysis and/or differing opinions on conclusions/next steps

**Alternative Solutions**
Don’t know how to solve the problem
Focus on fringe/easy solutions, instead of the underlying problem

**Evaluation of Alternatives**
Communication gap and process limits cross-sharing to view in comprehensive/holistic manner
Theory versus reality

**Decision and Action Plan**
Difficult, controversial and necessary discussions
Experimental, impact unknown
Mounting “Frustration”
- FERC pressure building
- State regulators perform own analysis
- Stakeholders “scratching their heads”
- Natural tendency to retreat to what is comfortable
- Interpretation of Tariff Vagueness
  - FERC Complaint ISO-versus NEPGA

Winter 2012/2013
- Electric reliability concerns
- “Situation unsustainable” declared
- Secondary market prices for gas and electric prices

The spotlight and recent winter experience are contributing to momentum.

What has contributed to NE current concerns:
- Electric market design - lack of incentives and funding for reliable fuel
- NE generators turned back virtually all pipeline FT
- Near total reliance on secondary market for generation
- LNG imports, warmer than normal winters and low secondary market prices - delayed rude awakening until this past winter
- Problem solving challenges described earlier

What has assisted in addressing current NE concerns:
- At least 12 years of gas/electric coordination efforts in region
- Enhanced communication between gas and electric
- Improving cross industry knowledge
- Pipelines have offered high flexibility
- Trial program information sharing
- Day ahead bidding period 10 am
Questions Remain

- Access to growing nearby shale gas production is increasingly restricted to firm transportation
- Nothing on the horizon yet that addresses the gas infrastructure issue
  - No evidence of electric industry participation in pipeline expansions
  - Out of market “supplemental procurement” for this winter currently focused on increased oil use, not LNG imports
- Continued lack of fuel long term reliability funding - mismatch of long term based gas capacity contracts with electric capacity revenues
- Electric market process to make decisions/adjustments is complex and difficult
  - Information sharing controversial and 6 mo program implemented by FERC
  - One hour time difference in day ahead bidding was controversial and required FERC to overrule ISO position
  - Major dispute on tariff interpretation – NEPGA vs. ISO-NE
- Is the historical process most appropriate to effectively address major structural issues/changes?

☑️ Gas industry remains committed to contributing to solutions in a positive and pro-active manner consistent with its culture of addressing and settling issues.
Pipeline Investment in the Age of the Independent Power Producer

Robert Stoddard
Energy Bar Association, Northeast Chapter
June 5, 2013

Introducing CRA – a Snapshot of the Company

Overview

• Founded in 1965
• Publically traded (NASDAQ: CRAI)
• Headquarters in Boston, USA with offices throughout North America and Europe
• 500+ Consultants

Industry Sectors

- Aerospace & Defence
- Broadcast and Media
- Energy
- Financial markets
- Healthcare
- Industrial products
- Oil and gas
- Life sciences
- Mining, metals & materials
- Telecommunications

Service Platforms

Strategy
Litigation & Regulation
Economics & Finance
Operations

Clients

- Businesses
- Governments & Agencies
- Law Firms
- Accounting Firms

² Private and Confidential
Houston, we have a problem...

- Gas basis spread to Algon Gates through 2019...
  - $1.65/MMBtu vs. Henry Hub
  - $1.21/MMBtu vs. Tennessee Zone 6 NY
  - Annual consumption ~1Tcf means more than a $1bn in annual basis cost

- Electric reliability challenged
  - Gas/electric integration is major RTO topic
  - Proposed “Performance Incentives”
    - Targets gas-fired gen to buy firm power or hold secondary fuel
    - Likely to add $2bn in capacity charges to consumers

- Gas demand is growing
  - High oil prices driving out oil-fired generation
  - Renewed shift in home heating fuel to gas

With $3bn / year on the table, how do we get new pipeline capacity built?

Algonquin basis versus pipeline capacity utilization

Source: EIA
Nearly half of New England gas burn is for electricity

![Bar chart showing gas burn in different regions of the US.]

But electric generators in New England don’t usually buy firm gas transportation

Mind the Gap

- Gas demand for NE electric generation is fairly easy to forecast in aggregate
  - About 1.25 Bcf/day
  - Monthly shape is predictable with modest error
- Gas demand for any one electric generator is very difficult to forecast
  - Many gas-fired CCs with similar performance / similar offer prices
  - Small changes in commitment → large changes in plant gas burn
The investment conundrum

• Rational IPPs resist buying firm gas
  – Can’t predict own use
  – Uncertain market for resale
  – No regulated rates to absorb costs
• Rational pipeline owners require firm gas contracts
  – Traditional low-risk business model
  – FERC requirement
  – Financing requirement

How do we bridge this gap between generators and pipelines?

A modest proposal

• Create “Regional Pipeline Operator” (RPO)
  – Fundamental rethink of pipeline model
  – Analogous to, but separate from, ISO-NE
• Planning function
  – Develop Regional Pipeline Expansion Plan (RPEP) to meet future needs
  – Solicit competitive bids to own & operate needed new capacity
  – Backstop construction authority through interstate agency (similar to Port Authority of New York & New Jersey)
• Consolidated tariff authority
  – Common tariff rate throughout region
  – Meets aggregate revenue requirement of existing and new pipes
• Possible role in facilitating transparent intraday gas trading
Benefits of RPO

- Gets infrastructure built without firm contracts with customers
  - Tariff authority is bankable, as we know from power sector
- Ensures cost recovery of existing and new investment
- Distributes costs equitably among all users
  - Allows, but does not require, firm delivery at premium price, similar to FTRs
  - Eliminates pancaked rates for use of multiple pipelines
  - Enhances efficient utilization of pipeline and pipeline connectors
- Improves arbitrage among pricing points
  - Improves efficiency of power sector
  - Reduces end-user costs
  - Opens door to more liquid and transparent intra-day pricing
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WHO WE ARE

Shell Energy is a leader in energy products and services:
- Marketing – Wholesale Natural Gas and Power
- Trading – Physical, Financial, and Environmental Product offerings
- Producer Services – Fuel and supply management, transport optimization, inventory management
- LNG – Royal Dutch Shell is a market leader in LNG, with existing and planned LNG projects throughout the world
- Financial Rating: A-/A2*

*Credit ratings by S&P and Moody’s

CURRENT FACTS ABOUT SHELL ENERGY NORTH AMERICA

- 13 billion cubic feet of natural gas per day (2012)
- 1.5 billion cubic feet per day of Shell equity natural gas
- 220 million megawatt hours of power annually
- 5,000 megawatts of power generation capacity under management
- More than 630 energy professionals
By pooling additional resources, Shell Energy provides 13 Bcf/d of natural gas.

**Power**
- More than 220 million MWH of power sold annually
- 5,000 megawatts of power generation
CONTRACTS RELATED TO GENERATION

1. Energy Conversion Agreements (Tolling Agreements) – SENA pays the generator a monthly capacity payment and variable charge to convert natural gas to electric energy.

2. Power Purchase Agreements

3. Energy Management Agreements – SENA provides services to a generator, but does not control the output. May include “optimization”, gas supply and scheduling services.

4. Schedule Coordinator Agreements – SENA is paid to submit schedules for generators.

NATURAL GAS MARKET PARTICIPANTS

Figure reproduced with the permission of Cornerstone Research.
NATURAL GAS MARKET PARTICIPANTS

Purchase And Sale Volume By Company

IN THE GAS MARKET

Summary of FERC Form 552 Data for 2012 & 2011

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<td>9.6</td>
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<tr>
<td>Cheniere</td>
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<td>Total of Above</td>
<td>37,878.9</td>
<td>46,283.5</td>
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<td>119.4</td>
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Source: Platts daily, May 6, 2013
TRADITIONAL U.S. PIPELINE CORRIDORS


PIPELINES IN TRANSITION

PIPELINE EXPANSIONS

Proposed Pipeline Projects


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We may have used certain terms, such as resources, in this presentation that United States Securities and Exchange Commission (SEC) strictly prohibits us.
Gas & Electric: Are we on the road to a reliable future?

Richard Kruse
VP Regulatory
Spectra Energy Asset Portfolio

Connecting the largest diverse markets with growing supply

Interrelated Gas/Electric Issues

Gas/Electric issues can be sorted into 3 sets of interrelated issues

Communication  Scheduling and Coordination  Infrastructure and Services
Communication

February 13, 2013 - FERC technical conference on coordination between natural gas and electricity markets

• The general perception is that reliability will be enhanced if electric operators and gas operators communicate on status of their respective operations

• How much communication is too much? When must communication be public and what can be private are key regulatory questions

• This is not a market-affiliate communication issue, but rather what constitutes undue discrimination under Section 4(b) of the Natural Gas Act

The industry needs FERC guidance regarding electric rules and gas rules which potentially restrict communications

Scheduling & Coordination

Standardized

• Gas Day is standardized for North America

• Gas Scheduling is standardized for North America

• Some pipelines provide Hourly Scheduling – including Spectra Energy pipelines

Not Standardized

• Electric Day varies by ISO

• Electric Scheduling varies by ISO

• Prior efforts to standardize Gas/Electric Day were unsuccessful

• NAESB efforts to identify solutions

• FERC April 25 Technical Conference
The Need for Natural Gas Infrastructure

Communication, Scheduling and Coordination concerns are merely symptoms of the real problem:

**Insufficient gas pipeline infrastructure to support growing gas demand**

The disconnect:

- Wholesale electric markets dispatch plants based on price with no incentives for reliability
- The dispatch model discourages generators from holding firm capacity contracts
- Pipelines, however, need long term contracts to support infrastructure investment to meet growing demand

Gas-Fired Power Generation Dynamics

**Texas Eastern** (M2 and M3 Zones)

![Graph showing Power Market Demand Growth and Peak Demand vs. Firm Capacity Contracting](image)

- **Power Market Demand Growth (MDth/d)**
  - Average Daily Flows

- **Peak Demand vs. Firm Capacity Contracting (MDth/d)**
  - Summer Peak: 1577
  - Winter Peak: 1172
  - Contracted: 421

- **Generators’ Firm Capacity vs W11/12 Peak Day**

- **Burn Potential**: 35.9%
Demand Growth Outpaces Firm Contracts

Algonquin Gas Transmission – serving the northeast market

Power Market Demand Growth (MDth/d)

Peak Demand vs. Firm Capacity Contracting (MDth/d)

Demand Growth Outpaces Firm Contracts

Reliability & Experience with Power Generation

Spectra Energy’s Power Generation Experience

• Over 55 GW attached
• Multiple services offered:
  – 42 Nomination cycles on TETCO
  – No-notice Firm Transportation
  – Firm Transportation
  – Secondary Firm Transportation
  – Capacity Release
  – Interruptible Transportation
  – Park & Loan
Benefits of Firm Transportation to Power Generators

• During peak winter days when pipeline capacity is constrained, generators without firm mainline transport may not be able to get scheduled quantities to their delivery point
• Firm transport agreements to a liquid point provide:
  – Generators the ability to secure lower cost natural gas
  – Increased power plant reliability
  – Decreased power cost to the grid, which offsets demand charges for firm supply and transport

To provide reliable and economical gas-fired generation, power plants need firm mainline capacity back to a liquid supply point

Texas Eastern Appalachian Shale Supply Interconnect Program

<table>
<thead>
<tr>
<th>54 Requests In-Service &amp; Under Agreement</th>
<th>14.2 Bcf/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>(requested tap &amp; posted M&amp;R capacity)</td>
<td></td>
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<tr>
<td>Current Appalachian Supply</td>
<td>1.4 – 1.9 Bcf/d</td>
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<tr>
<td>33 In-Service (posted M&amp;R capacity)</td>
<td>6.6 Bcf/d</td>
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<tr>
<td>21 In Progress &amp; Under Agreement (Scheduled 2013 In-Service)</td>
<td>7.6 Bcf/d</td>
</tr>
</tbody>
</table>

Texas Eastern Appalachian Shale Supply Growth
U.S. Transmission – Northeast Expansion Projects & Opportunities

Continued growth opportunities connecting Appalachian supplies to our diverse markets

- Power generation – up to 2.5 Bcf/d of incremental demand in Midwest and Northeast through 2020
- Oil to gas conversions in New England / New York
- Opportunities to serve growth in existing and new markets

$4 B of investment opportunities in 2013-2016

Making Reliable Choices

How will the electric market value reliability?

As natural gas demand grows, interruptible service will be harder to come by

Contract service level is synonymous with reliability of service
- Firm contracts offer the highest level of service priority

Wholesale electric market rules need to encourage, not disincentivize, firm contracts

Reliable, secure energy tomorrow rests with the choices we make today. We must choose well.
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WHO WE ARE

Shell Energy is a leader in energy products and services:

- Marketing – Wholesale Natural Gas and Power
- Trading – Physical, Financial, and Environmental Product offerings
- Producer Services – Fuel and supply management, transport optimization, inventory management
- LNG – Royal Dutch Shell is a market leader in LNG, with existing and planned LNG projects throughout the world
- Financial Rating: A-/A2*

*Credit ratings by S&P and Moody’s

CURRENT FACTS ABOUT SHELL ENERGY NORTH AMERICA

- 13 billion cubic feet of natural gas per day (2012)
- 1.5 billion cubic feet per day of Shell equity natural gas
- 220 million megawatt hours of power annually
- 5,000 megawatts of power generation capacity under management
- More than 630 energy professionals
DIVERSE SUPPLY – NATURAL GAS

By pooling additional resources, Shell Energy provides 13 Bcf/d of natural gas.

DIVERSE SUPPLY – POWER

- More than 220 million MWH of power sold annually
- 5,000 megawatts of power generation
CONTRACTS RELATED TO GENERATION

1. Energy Conversion Agreements (Tolling Agreements) – SENA pays the generator a monthly capacity payment and variable charge to convert natural gas to electric energy.
2. Power Purchase Agreements
3. Energy Management Agreements – SENA provides services to a generator, but does not control the output. May include “optimization”, gas supply and scheduling services.
4. Schedule Coordinator Agreements – SENA is paid to submit schedules for generators.

NATURAL GAS MARKET PARTICIPANTS

BREAKDOWN OF FORM 552 TRANSACTION VOLUME BY COMPANY CATEGORY

Figure reproduced with the permission of Cornerstone Research.
NATURAL GAS MARKET PARTICIPANTS

Purchase And Sale Volume By Company

Figure reproduced with the permission of Cornerstone Research

IN THE GAS MARKET

Summary of FERC Form 552 Data for 2012 & 2011

<table>
<thead>
<tr>
<th>Company</th>
<th>Bcf</th>
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Source: FERC Form 552, May 6, 2013
TRADITIONAL U.S. PIPELINE CORRIDORS

Corridors Serving Northeast Market: 2 Southwest to Northeast; 8 Western Canada to Northeast; 9 Eastern Offshore Canada to Northeast (Sable Island/Canaport/Panuke).


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DEFINITIONS AND CAUTIONARY NOTE

The companies in which Royal Dutch Shell plc directly and indirectly owns investments are separate entities. In this presentation “Shell”, “Shell group” and “Royal Dutch Shell” are sometimes used for convenience where references are made to Royal Dutch Shell plc and its subsidiaries in general. Likewise, the words “we”, “us” and “our” are also used to refer to subsidiaries in general or to those who work for them. These expressions are also used where no useful purpose is served by identifying the particular company or companies. “Subsidiaries”, “Shell subsidiaries” and “Shell companies” as used in this presentation refer to companies over which Royal Dutch Shell plc either directly or indirectly has control. Companies over which Shell has joint control are generally referred to as “joint ventures” and companies over which Shell has significant influence but neither control nor joint control are referred to as “associates”. In this presentation, joint ventures and associates may also be referred to as “equity-accounted investments”. The term “Shell interest” is used for convenience to indicate the direct and/or indirect (for example, through our 23% shareholding in Woodside Petroleum Ltd.) ownership interest held by Shell in a venture, partnership or company, after exclusion of all third-party interest.

This presentation contains forward-looking statements concerning the financial condition, results of operations and businesses of Royal Dutch Shell. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements are statements of future expectations that are based on management’s current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements. Forward-looking statements include, among other things, statements concerning the potential exposure of Royal Dutch Shell to market risks and statements expressing management’s expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as “anticipate”, “believe”, “could”, “estimate”, “expect”, “goals”, “intend”, “may”, “objectives”, “outlook”, “plan”, “probably”, “project”, “risks”, “schedule”, “seek”, “should”, “target”, “will” and similar terms and phrases. There are a number of factors that could affect the future operations of Royal Dutch Shell and could cause those results to differ materially from those expressed in the forward-looking statements included in this presentation, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for Shell’s products; (c) currency fluctuations; (d) drilling and production results; (e) reserves estimates; (f) loss of market share and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including regulatory measures addressing climate change; (k) economic and financial market conditions in various countries and regions; (l) political risks, including the risks of expropriation and renegotiation of the terms of contracts with governmental entities, delays or advancements in the approval of projects and delays in the reimbursement for shared costs; and (m) changes in trading conditions. All forward-looking statements contained in this presentation are expressly qualified in their entirety by the cautionary statements contained or referred to in this section. Readers should not place undue reliance on forward-looking statements. Additional risk factors that may affect future results are contained in Royal Dutch Shell’s 20-F for the year ended December 31, 2012 (available at www.shell.com/investor and www.sec.gov). These risk factors also expressly qualify all forward-looking statements contained in this presentation and should be considered by the reader. Each forward-looking statement speaks only as of the date of this presentation, [insert date]. Neither Royal Dutch Shell plc nor any of its subsidiaries undertake any obligation to publicly update or revise any forward-looking statement as a result of new information, future events or other information. In light of these risks, results could differ materially from those stated, implied or referred from the forward-looking statements contained in this presentation.

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Conference
Speaker Biographies
The Honorable Cory A. Booker, 41, is the Mayor of Newark, New Jersey. He took the oath of office as Mayor of New Jersey’s largest city on July 1, 2006 following a sweeping electoral victory and was re-elected to a second term on May 11, 2010.

Elected with a clear mandate for change, Mayor Booker has begun work on realizing a bold vision for the city. Newark’s mission is to set a national standard for urban transformation by marshalling its resources to achieve security, economic abundance and an environment that is nurturing and empowering for individuals and families.

Mayor Booker and his Administration have made meaningful strides towards achieving the City’s mission. On April 1, 2010, the City of Newark experienced its first homicide-free month in more than forty years and was recognized in July 2008 for leading the nation among large cities for reductions in shootings and murders, achieving decreases of more than 40% reductions in both categories. Radical transformation of the Newark Police Department under Mayor Booker’s leadership, together with the deployment of over 100 surveillance cameras throughout City, has led to Newark setting the nationwide pace for crime reduction.

Among other recent notable achievements under Mayor Booker’s leadership, the City of Newark has committed to a $40 million transformation of the City’s parks and playgrounds through a groundbreaking public/private partnership. The Booker Administration has also doubled affordable housing production.

Mayor Booker’s political career began in 1998, after serving as Staff Attorney for the Urban Justice Center in Newark. He rose to prominence as Newark’s Central Ward Councilman. During his four years of service from 1998-2002, then-Councilman Booker earned a reputation as a leader with innovative ideas and bold actions, from increasing security in public housing to building new playgrounds. This work was the foundation for his leadership as Mayor. For this work, he has been recognized in numerous publications, including, among others, Time, Esquire, New Jersey Monthly (naming him as one of New Jersey’s top 40 under 40), Black Enterprise (naming him to the Hot List, America’s Most Powerful Players under 40) and The New York Times Magazine.

Reflecting his commitment to education, Mayor Booker is a member of numerous boards and advisory committees including Democrats for Education Reform, Columbia University Teachers’ College Board of Trustees and the Black Alliance for Educational Options. Mayor Booker received his B. A. and M. A. from Stanford University, a B. A. in Modern History at Oxford University as a Rhodes Scholar, and completed his law degree at Yale University.
Stefanie A. Brand serves as the Director for the Division of Rate Counsel, a position she has held since October 1, 2007. The Division of Rate Counsel represents the interests of consumers of regulated electric, natural gas, water/sewer, telecommunications, cable TV service, and insurance (residential, small business, commercial and industrial customers).

Rate Counsel's mission is to make sure that all classes of utility consumers receive safe, adequate and proper utility service at affordable rates that are just and nondiscriminatory. Rate Counsel is a member of several state utility policy making groups and also represents consumers in setting energy and telecommunications policy that will affect the provision of services into the future. The New Jersey Legislature charged Rate Counsel with being "devoted to the maximum extent possible to ensuring adequate representation of the interest of those consumers whose interest would otherwise be inadequately represented in matters within the jurisdiction of the Division of Rate Counsel." The Division's website is http://www.state.nj.us/rpa/

Prior to joining Rate Counsel when it was then part of what is now the defunct Department of the Public Advocate, Stefanie was the Assistant Attorney General in Charge of Litigation for the Division of Law within the Department of Law and Public Safety. In this position she oversaw all civil litigation for the state. Her tenure with the Division of Law included work on a variety of issues such as child welfare, environmental regulation, human services, employment and tort law.

Stefanie brings almost 25 years of legal experience to the Division. She has spent 17 years advocating on behalf of the people of New Jersey. After 5 years in private practice, she joined the Division of Law in 1992. She worked as a Deputy Attorney General for 10 years, focusing on solid waste, environmental cases and federal litigation. In 2002, Stefanie was named Deputy Attorney General in Charge of Litigation and in 2003, she was named Assistant Attorney General.

Stefanie graduated from Columbia University School of Law in 1986, and clerked for Associate Justice Gary Stein of the New Jersey State Supreme Court.
Edward H. Comer is Vice President, General Counsel, and Corporate Secretary at the Edison Electric Institute. He began at EEI as a staff attorney in 1981 and became Vice President and General Counsel in 1998. Ed was elected Corporate Secretary in September, 2011.

At EEI, Ed is responsible for all legal issues affecting EEI and its members and works directly on the critical policy issues affecting the electric industry. He represents EEI in Congress and in proceedings before federal regulatory agencies, including the Federal Energy Regulatory Commission, the Department of Energy, the Environmental Protection Agency and several others agencies. He also represents EEI before state legislative and administrative bodies and with state officials on matters of generic industry interest. Currently he is personally engaged in issues involving environmental rules, cyber security, distributed generation, storm recovery and general utility regulation.

Ed manages an active litigation practice at EEI. EEI regularly appears as an amicus or intervenor in matters of general electric utility interest in cases before the U.S. Supreme Court, Federal Courts of Appeals and the highest Courts in individual states. A recent successful case is American Electric Power Co. v. Connecticut, where the U.S. Supreme Court held that federal courts lacked authority to consider common law tort claims relating to emissions of greenhouse gases.

Ed also hosts EEI's biannual Legal Conferences, which discuss legal issues of significance to the electric industry. EEI's Legal Conferences are widely regarded as an excellent source of cutting-edge information within the electric industry and are certified for Continuing Legal Education Credits in over 30 states.

Ed holds a Bachelors degree from the University of Chicago, where he specialized in Russian History, and a Law degree from the University of Pennsylvania Law School. He is an active member of the American Bar Association, the Energy Bar Association and the Association General Counsel Forum. Prior to joining EEI, he spent several years in private practice at Terris and Sunderland in Washington, D.C. Before that, he worked at the Office of Hearings and Appeals at the U.S. Department of Energy (DOE) on oil rate regulation and allocation issues.
Robert S. (Bob) Fleishman

Bob Fleishman, Of Counsel at Covington & Burling LLP in Washington D.C. focuses on energy, white collar defense, and ADR matters for a range of clients.

He represents and advises energy companies, financial firms, traders, and others in FERC and CFTC non-public enforcement investigations involving allegations of market manipulation and other matters, represents clients in FERC audits, and advises and trains clients on FERC and CFTC compliance and enforcement matters.

Before joining Covington in 2003, he served as General Counsel and Vice-President of Corporate Affairs and Legislative and Regulatory Policy for Constellation Energy Group, and General Counsel and Vice-President of Corporate Affairs for BGE. From 1979-1985, Bob worked at FERC in various capacities, including in the Division of Enforcement where he investigated and litigated various matters.

From 2011-12, Bob was Chairman of the Committee on Compliance and Enforcement for the Energy Bar Association (EBA). He is Editor-in-Chief of the Energy Law Journal and was President of the EBA in 1999-2000.

In the ADR arena, Bob was the Project Manager of the Energy ADR Forum and its report, “Dispute Resolution in the Energy Industry: The Better Way,” is a member of the Energy Panel of the International Center for Dispute Resolution, and served as Chairman of EBA’s ADR Committee.

Bob graduated from Boston University School of Law and received his undergraduate degree, *cum laude*, from Georgetown University. He has been recognized in Chambers USA for Energy (2011-2012); Best Lawyers in America for Energy Law (2007-2013); and Washington DC Super Lawyers for Energy & Natural Resources (2011-2012).
Michelle Gardner is Senior Counsel, Regulatory for Capital Power Corporation. Capital Power is an Alberta, Canada-based company that owns approximately 1050 MW of gas-fired generation in New England. Michelle represents Capital Power in the New England Power Pool (NEPOOL) committee process and serves on the board of the New England Power Generators Association. Michelle is currently Co-Chair of the NECA Power Markets Committee and is on the Board of the Northeast Chapter of the EBA.

Prior to Capital Power, Michelle was a Counsel at Day Pitney LLP and acted as NEPOOL Counsel for seven years, primarily on market issues in New England. Michelle graduated magna cum laude from Catholic University with her law degree and holds a bachelor’s degree from the College of the Holy Cross.
Larry Gasteiger is the Deputy Director of the Office of Enforcement. Previously, Mr. Gasteiger was the Director of the Division of Tariffs and Market Development - East in the Office of Energy Market Regulation. Prior to that, he held several other positions at the Commission, including Deputy Associate General Counsel, Legal Advisor to Chairman Joseph T. Kelliher, and attorney in the Solicitor's Office. Before joining FERC in 1997, Mr. Gasteiger was an attorney in the General Counsel's Office at the Commodity Futures Trading Commission, and from 1989 to 1991 he served as a law clerk for the Honorable Edwin M. Kosik in the United States District Court for the Middle District of Pennsylvania.

Mr. Gasteiger is a graduate of the University of Pennsylvania and the Dickinson School of Law. He resides in Fairfax, Virginia with his wife and three children.

Contact Information:

Telephone: 202-502-8100
FAX: 202-502-6449
888 First Street, NE
Washington, DC 20426
Shari C. Gribbin  
Manager, FERC Compliance & 
Assistant General Counsel  
Exelon Corporation

Ms. Gribbin is Manager, FERC Compliance and Assistant General Counsel with Exelon, which owns and operates generation, transmission and distribution facilities as well as wholesale power marketing and retail energy supply divisions. Ms. Gribbin has been with Exelon for 13 years. In her current role she is responsible for the development and implementation of the corporate level FERC compliance program. She also serves as lead counsel on all NERC 693 and Cyber Security legal issues and provides support on FERC compliance related matters. Prior to moving into this role, Ms. Gribbin worked in the Exelon Legal Regulatory practice group as counsel on all aspects of electric and gas operations and reliability issues, including FERC compliance, Standards of Conduct and the “pre-NERC” reliability and Cyber Urgent Action Standard constructs.

Ms. Gribbin has a BA in Legal Studies and Criminal Justice from the University of Central Florida and a JD from Temple University School of Law. She served as President for the Network of Exelon Women from 2007 – 2010 and has served as a founder, mentor and speaker for several youth and diversity organizations. Her article *Diversity: On Responding to Challenges*, was published in the National Association of Women Lawyers Vol. 91, No. 4 (2006). Ms. Gribbin also co-founded the National Energy Compliance Forum (NECF) and served as the 2011 and 2012 Chair for that organization.
Robert M. Hanna Biography

Robert M. Hanna, Esquire, was appointed President of the New Jersey Board of Public Utilities by Governor Christopher J. Christie on December 21, 2011. As President, Bob also serves as a member of the Governor’s Cabinet. Prior to his nomination, Bob served as Director of the Division of Law within the New Jersey Department of Law and Public Safety, where he was responsible for overseeing a division with more than 500 attorneys and for the supervision of all Division of Law matters.

Prior to joining the Office of the N.J. Attorney General in January 2010, Bob was a director in the Newark-based law firm of Gibbons P.C., in Newark, N.J. from 2006-2010. Prior to entering private practice, Bob spent 16 years with the U.S. Attorney’s Office for the District of New Jersey. There, he worked in the Civil and Fraud Divisions before serving in a variety of roles that included Chief of the Securities - Health Care Fraud Unit and Criminal Health Care Fraud Coordinator.
Ralph Izzo
Chairman of the Board, President and Chief Executive Officer
Public Service Enterprise Group Incorporated

Biography
Ralph Izzo was elected chairman and chief executive officer of Public Service Enterprise Group Incorporated (PSEG) in April 2007. He was named as the company’s president and chief operating officer and a member of the board of directors of PSEG in October 2006. Previously, Mr. Izzo was president and chief operating officer of Public Service Electric and Gas Company (PSE&G).

Since joining PSE&G in 1992 Mr. Izzo was elected to several executive positions within PSEG’s family of companies, including PSE&G senior vice president – utility operations, PSE&G vice president – appliance service, PSEG vice president - corporate planning, and PSE&G vice president - electric ventures. In these capacities he broadened his experience in the areas of general management, strategic planning and finance.

Mr. Izzo is a well-known leader within the utility industry, as well as the public policy arena. He is frequently asked to testify before Congress and speak to organizations on matters pertaining to national energy policy.

Mr. Izzo’s career began as a research scientist at the Princeton Plasma Physics Laboratory, performing numerical simulations of fusion energy experiments. He has published or presented over 35 papers on magnetohydrodynamic modeling. Mr. Izzo received his Bachelor of Science and Master of Science degrees in mechanical engineering and his Doctor of Philosophy degree in applied physics from Columbia University. He also received a Master of Business Administration degree, with a concentration in finance from the Rutgers Graduate School of Management. He is listed in numerous editions of Who’s Who and has been the recipient of national fellowships and awards. Mr. Izzo has received Honorary Degrees from the New Jersey Institute of Technology (Doctor of Science), Thomas A. Edison State College (Doctor of Humane Letters), and Bloomfield College (Doctor of Humane Letters).

Mr. Izzo serves as chair of Rutgers University Board of Governors and on the board of directors for the New Jersey Chamber of Commerce, the New Jersey Utilities Association, the Edison Electric Institute (EEI), the Nuclear Energy Institute (NEI), the Institute for Nuclear Power Operations (INPO), the National Center on Addiction and Substance Abuse at Columbia University (CASA), and The Center for Energy Workforce Development. He is also a member of the Columbia University School of Engineering Board of Visitors and the Princeton University Adlunger Center for Energy and the Environment Advisory Council, as well as a member of the Visiting Committee for the Department of Nuclear Engineering at MIT.
The Honorable Joseph T. Kelliher
Executive Vice President,
Federal Regulatory Affairs


Mr. Kelliher served as Chairman of the Federal Energy Regulatory Commission (FERC) from 2005 to 2009. In that role, he served as the chief executive officer of the agency, managing 1,400 employees and a $260 million annual budget. Among the highlights of his chairmanship was efficient implementation of the Energy Policy Act of 2005, the largest expansion in FERC regulatory authority since the 1930s. This law gave FERC a new mission to assure reliability of the interstate power grid, granted the agency strong enforcement authority for the first time, and expanded FERC authority in other areas. Chairman Kelliher pursued a series of reforms to promote competitive wholesale power and natural gas markets, improve FERC economic regulation, and strengthen the U.S. energy infrastructure.

Mr. Kelliher has spent his entire professional career working on energy policy matters, serving in a variety of roles in both the public and private sectors. These include senior policy advisor to the Secretary of Energy, and majority counsel to the House Commerce Committee, as well as positions with private corporations, trade associations, and law firms.

Mr. Kelliher earned a bachelor of science degree from Georgetown University, School of Foreign Service, and a juris doctor degree, magna cum laude, from The American University Washington College of Law.

NextEra Energy, Inc. (NYSE: NEE) is a leading clean energy company with 2009 revenues of more than $15 billion, nearly 43,000 megawatts of generating capacity, and more than 15,000 employees in 28 states and Canada. Headquartered in Juno Beach, Fla., NextEra Energy's principal subsidiaries are NextEra Energy Resources, LLC, the largest generator in North America of renewable energy from the wind and sun, and Florida Power & Light Company, which serves approximately 4.5 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country. Through its subsidiaries, NextEra Energy collectively operates the third largest U.S. nuclear power generation fleet. For more information about NextEra Energy companies, visit these Web sites: www.NextEraEnergy.com, www.NextEraEnergyResources.com, www.FPL.com.
Michael J. Kormos, PJM senior vice president of Operations, is responsible for all services that touch reliability, including System Operations, System Planning, Information and Technology Services, Security and Regional Coordination.

Previously, Mr. Kormos was the vice president of System Operations and has served in various management and engineering positions in the Operations Division. He was responsible for the oversight of the day-to-day operations and implementation of Locational Marginal Pricing and the new market structures. Formerly he was a member of the Operating Committee for the North American Electric Reliability Corporation (NERC) and currently sits on the Board of Directors for the ReliabilityFirst Corporation (RFC), the Executive Committee of the Eastern Interconnection Planning Collaborative (EIPC) and the Industry Leaders Council for the Consortium for Electric Reliability Technology Solutions (CERTS).

Mr. Kormos earned a bachelor of science in electrical engineering from Drexel University and a master of business administration from Villanova University.

PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 58 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region’s transmission grid, which includes 61,000 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. Visit PJM at www.pjm.com.
Richard J. Kruse
Vice President, Regulatory and
FERC Chief Compliance Officer
Spectra Energy Transmission

Richard Kruse is vice president of regulatory and FERC chief compliance officer for Spectra Energy Transmission (SET). He is responsible for the development and management of SET’s regulatory strategy and action with the Federal Energy Regulatory Commission (FERC) and directs the pipeline group’s position in the state proceedings in each of the states served by the company’s pipelines. He is also responsible for managing the company’s involvement in the North American Energy Standards Board and serves on the NAESB Board of Directors.


Kruse received a Bachelor of Science degree in economics from Texas Tech University in Lubbock and a law degree from the University of Houston.
Executive Profile

Ralph A. LaRossa

President and Chief Operating Officer

Public Service Electric and Gas Company

Ralph A. LaRossa was named president and chief operating officer of Public Service Electric and Gas Company (PSE&G), in October 2006. Prior to this position he was vice president - electric delivery for PSE&G.

Mr. LaRossa joined PSE&G in 1985 as an associate engineer and advanced through a variety of management positions in the utility’s gas and electric operations. In 1998 he received Gas Industry Magazine’s Outstanding Manager of the Year Award. PSE&G is New Jersey’s largest electric and gas utility.

Mr. LaRossa is a graduate of Stevens Institute of Technology and has completed the Harvard Business School’s Program for Management Development. He serves on the board of directors for the American Gas Association (AGA), New Jersey Utilities Association (NJUA), New Jersey Performing Arts Center (NJPAC), Partnership for a Drug-Free NJ, Choose New Jersey, and Bergen County’s United Way. He also serves on the board of trustees for Montclair State University, Liberty Science Center and the Newark Alliance.
Executive Profile

Tamara L. Linde (Tammy)
Vice President - Regulatory

Tamara L. Linde was named vice president - regulatory of PSEG in December 2006. She is responsible for the federal and state regulatory matters of the PSEG companies. Additionally, Tamara manages the corporate legal group within the PSEG law department.

Ms. Linde joined the law department of Public Service Electric and Gas Company (PSE&G), as an attorney in 1990 handling a variety of natural gas and electric regulatory and transactional matters. After holding several other legal positions at PSE&G she became general solicitor, in 2000. In that position she was responsible for the regulatory affairs of the PSEG companies including electric, gas and nuclear matters. She has had significant experience working on regulatory matters before various state and federal regulatory agencies on industry issues relating to electric transmission and distribution and energy markets.

Ms. Linde is a member of the New Jersey, New York, District of Columbia and Texas bars and served as chair of the Energy Bar Association Electricity Regulation and Compliance Committee during the 2009-2010 term. Ms. Linde graduated from Seton Hall University School of Law and from Seton Hall University with a bachelor’s degree. She currently serves on PSEG’s Compliance Council, PSEG’s Disclosure Committee and PSE&G’s Real Property Committee. Ms. Linde also serves as a member of the Board of Trustees of New Jersey After 3, a non-profit organization dedicated to expanding after school opportunities for New Jersey’s kids.
Markian M.W. Melnyk

Markian Melnyk is a founder and President of Atlantic Grid Development, LLC (AGD). AGD is developing the Atlantic Wind Connection project, an offshore high-voltage transmission backbone designed to efficiently serve Mid-Atlantic region offshore wind energy parks while also making the congested land-based transmission grid more reliable and efficient.

Richard Miller is Director of the Energy Markets Policy Group at Con Edison, which advocates on federal energy policy issues and represents the company at the New York ISO and PJM RTO. Previously he was an assistant general counsel in the regulatory services department at Con Edison where he worked on legal matters relating to the Con Edison steam system, renewable power and energy efficiency. From 1998-2003, he was Senior Vice-President for Energy at the New York City Economic Development Corporation (where he oversaw City energy policy). Prior to 1998, he was an energy regulatory attorney for Cohen, Dax & Koenig in Albany, New York, and a litigation associate at Cohen, Weiss and Simon and Sullivan & Cromwell in New York City. He is a graduate of Amherst College and New York University School of Law. From 1980-1982, Mr. Miller was a Peace Corps Volunteer in West Africa.
Commissioner John R. Norris

John R. Norris was nominated by President Barack Obama to the Federal Energy Regulatory Commission in 2010 and reconfirmed by the U.S. Senate in 2012 for a full term expiring in June 2017.

Commissioner Norris, a lawyer, has years of experience in energy policy and regulatory affairs. He most recently served as Chief of Staff to Secretary Tom Vilsack of the U.S. Department of Agriculture. Prior to joining the USDA, he served as Chairman of the Iowa Utilities Board (IUB) from 2005 to 2009. During his tenure as IUB Chairman, Commissioner Norris served on the National Association of Regulatory Utility Commissioners (NARUC) Electricity Committee and was Co-Chair of the 2009 National Electricity Delivery Forum.

During his IUB tenure, Commissioner Norris also served as a Board Member, Secretary and President of the Organization of Midwest Independent System Operator (MISO) States as well as Chairman of the MISO Demand Response Working Group. He also was a member of the FERC/NARUC Demand Response Collaborative.

Commissioner Norris also has served on the Board of Directors of the National Regulatory Research Institute, as a member of the Board of Trustees of the Iowa Power Fund and on the Advisory Councils of the Iowa Energy Center, the Financial Research Institute for the University of Missouri College of Business and the Center for Global and Regional Environmental Research at the University of Iowa.

In 1999 and 2000, Commissioner Norris was Chairman of the Iowa Electric Restructuring Task Force while serving as Chief of Staff for then-Iowa Governor Tom Vilsack. He also served as Chief of Staff for U.S. Representative Leonard Boswell (IA-3rd) from 1997 to 1998. From 1989 to 1993 he owned and managed a restaurant in Greenfield, Iowa, and he was State Director of the Iowa Farm Unity Coalition during the Farm Crisis of the 1980s.

Commissioner Norris graduated with distinction from the College of Law at the University of Iowa in 1995 and earned his undergraduate degree in 1981 from Simpson College in Indianola, Iowa.

Commissioner Norris, his wife, Jackie, and their three sons live in Washington, D.C.
LARRY R. PARKINSON

A South Dakota native, Mr. Parkinson received a bachelor of science degree from Northern State College and his law degree from Harvard Law School, he was an editor of the Harvard Law Review.

After serving as a civil litigator with the law firm of Ropes & Gray in Boston and a Judicial Law Clerk to U.S. District Judge William Young, Mr. Parkinson joined the United States Attorney’s Office for the District of Columbia, where he served as an Assistant United States Attorney for nine years. In that position, he served as a lead prosecutor in two of the largest corruption cases handled by the Department of Justice. In the Bank of Credit and Commerce International (BCCI) case, he led an investigation that resulted in the indictment of former Presidential advisor Clark Clifford and his law partner, Robert Altman. He was also a lead prosecutor in the U.S. House of Representatives Post Office investigation, which led to 12 convictions, including those of former House Ways & Means Committee Chairman Dan Rostenkowski, Congressman Joe Kolter, and House Postmaster Robert Rota.

Mr. Parkinson served as General Counsel of the U.S. Small Business Administration, where he managed and directed a legal office of over 200 attorneys.

In 1995, Mr. Parkinson joined the Federal Bureau of Investigation as Deputy General Counsel. In 1997, he was selected to be FBI General Counsel/Assistant Director, where he served for five years, reporting directly to FBI Directors Louis Freeh and Robert Mueller. In that position, he was responsible for all legal affairs in the FBI and was at the leading edge of a broad range of law enforcement, intelligence, and counterterrorism matters.

From 2002 to February 2010, Mr. Parkinson served as Deputy Assistant Secretary for Law Enforcement, Security & Emergency Management at the U.S. Department of the Interior. In that position, he was responsible for building a post-9/11 law enforcement, security, intelligence, and emergency management program for the Department, an organization with 70,000 employees that manages 20% of the lands in the United States and has the nation’s third largest contingent of federal law enforcement officers.

In March 2010, Mr. Parkinson joined the Office of Enforcement at the Federal Energy Regulatory Commission, where he currently serves as Director of the Division of Investigations.

Mr. Parkinson has twice received a Presidential Rank Award, an honor awarded by the President for distinguished federal service.
Matthew J. Picardi
Shell Energy North America (US), L.P. Biography

Matthew Picardi is the Vice President of Regulatory Affairs for Shell Energy’s East Region. This region covers most of Canada and the Eastern United States. He leads the Company’s advocacy efforts in regulatory proceedings and lobbying activities that support its natural gas, power, and environmental products marketing and trading operations. He serves on the Board of the Northeast Energy and Commerce Association and the Executive Committee of the National Energy Marketers Association. He also served as Chair of the Management Committee for the New York Independent System Operator.

Mr. Picardi has participated in numerous regulatory proceedings related to the development and operation of competitive energy markets before state and federal regulators. He is actively involved with Shell’s efforts to comment on proposed rules issued by the U.S. Commodities Futures Trading Commission for the implementation of the Dodd Frank Act as well as assessing its potential impact on Shell.

Mr. Picardi started his career with Niagara Mohawk Power Corporation, an electric and natural gas utility, as a regulatory and commercial transactions attorney. In 1996, he was appointed General Counsel of Niagara Mohawk Energy, the natural gas and power marketing affiliate of Niagara Mohawk. Prior to joining Shell Energy in 2002, Mr. Picardi served as Dynegy Inc.’s lead regulatory counsel for the Northeast United States for approximately three years.

Mr. Picardi holds a B.A from Hobart College and J.D. from Syracuse University College of Law. He lives in the Albany, New York area with his wife and three children.
About Sal Risalvato:

Sal Risalvato has served as NJGCA Executive Director since January 2007. He is a former small business owner, with over 35 years experience in the gasoline retail industry. Sal is a veteran of two previous gas crises in NJ, having operated an Exxon station during the gas lines of the 1979 Iran Oil Embargo, and then again in his role at NJGCA in the 2012 aftermath of Hurricane Sandy. Sal was the first gas station owner to sell and promote Gasohol during the 1979 Gas Crisis, and as a result has never given up on his vision of an America that is truly Energy Independent. Sal played a key role in the aftermath of Hurricane Sandy coordinating both power restoration and emergency gasoline deliveries to gas stations with the Governor’s office, State Police, Department of Defense, and PSE&G. As a small business advocate, Sal was recruited to testify over 20 times in both the U.S. House of Representatives and U.S. Senate on Energy, Environmental, and Health Care issues. His blunt-spoken style has won him national attention and he has been quoted on the editorial pages of the Wall Street Journal and Washington Post. Furthermore, Sal is no stranger to the political arena, having earned a prime speaking slot at the 1996 Republican National Convention and served as a senior-advisor on five New Jersey state-wide political campaigns, before focusing full time for NJGCA defending the state’s small businesses in Trenton. Preparing for future disasters such as Sandy and solving America’s reliance on foreign oil by increasing the use of alternate fuels such as Solar, Wind, Nuclear, Natural Gas, Hydrogen and Ethanol are among Sal’s priorities.
John P. Rudiak is the Senior Director of Energy Supply for Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company, gas utility subsidiaries of UIL Holdings. He holds a Bachelor of Science degree in Finance from Fairfield University, a Masters of Business Administration in Strategy and Policy from the University of Hartford and a Certificate of Advanced Study in Finance from Fairfield University. Mr. Rudiak has twenty five years of experience in gas supply planning and strategy, gas supply operations, retail and wholesale gas supply demand, pricing and markets, state and federal regulatory matters, energy industry issues, risk management and optimization, and gas supply accounting. Mr. Rudiak is a member of the AGA FERC regulatory committee and the Northeast Gas Association. He is the customer group chairman of the Alberta Northeast Gas consortium and the chairman of the New England gas distributor FERC group. He is also one of the tri-chairs overseeing the currently active New England gas/electric focus group process where all regional stakeholders are seeking to address gas and electric coordination issues in the region. Mr. Rudiak testifies frequently in state and federal proceedings on gas industry matters.
Robert Schimmenti is Vice President of Engineering and Planning for Con Edison, a position to which he was appointed in April 2010.

Mr. Schimmenti’s responsibilities include energy services, engineering, quality assurance, and energy efficiency. Through these areas, Con Edison assists customers from the initial stages of designing and building their electric and gas services, to reducing their energy use through energy-efficiency and demand-response programs. He is also leading the company’s storm hardening efforts.

Mr. Schimmenti has 25 years of experience in the utility business. He joined Con Edison as a management intern. He has held senior level positions in Electric Operations, Electric Construction, Control Center Operations, and Substation Operations.

He demonstrates his commitment to developing leaders through mentoring in Con Edison’s executive development program, and by teaching senior managers in the Company’s Business Academy.

He continues his advocacy for developing future generations and a sustainable environment through his work on the board of the Brooklyn Botanic Garden.

Mr. Schimmenti received a Bachelor of Engineering in Electrical Engineering from Hofstra University and a Master’s of Science in Management Technology from Polytechnic University.
CRA Senior Consultant Robert Stoddard is an energy economist with over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy markets. His recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly of Regional Transmission Organizations. He has testified to the Federal Energy Regulatory Commission as well as to the utility commissions and legislatures of several states on competitive market design, rates, and market power issues, and he as testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts. He had played central roles in the development and evolution of capacity markets throughout the United States to develop market-based mechanisms to support investment in generation, transmission, and pipeline infrastructure.