Issues Tracking
• Open Issues
  – None

• New Issues
2013 RTEP Baseline Update
Evaluation of 2018 Summer
- Base case analysis – complete
- Generator deliverability analysis – complete
- Load deliverability analysis – complete, finalizing solutions
- N-1-1 Thermal and Voltage Analysis
  - Complete, finalizing solutions

15 Year Analysis Update
- Complete, reviewed at October 2013 TEAC

24 Month RTEP Update
- Year 7 base case analysis (study year 2020) analysis is in progress
• **Project Scope Change**

  • Both high voltage and low voltage issues (possible voltage collapse) at Monocacy 230kV and surrounding areas under different system conditions

  • **B2235:**
    • Original scope: 130 MVAR reactor at Monocacy 230 kV
    • Previous Estimated Cost: $4M

  • New Scope: Install an SVC at the Monocacy 230kV bus to enable a smooth controlled Var operation between a range of -150 Mvar to 50 Mvar
    • New Estimated Cost: TBD

  • Projected IS Date: 6/1/2015
• **Operational Performance**

• High voltage conditions in the Wyoming area

• Install a 300 MVAR shunt reactor at AEP’s Wyoming 765KV station. (B2423)

• Estimated Cost: $10M

• Projected IS Date: 06/1/2018
Previous Retirement Related Upgrades

• The next four slides review retirement related upgrades that were approved in previous RTEP cycles but are no longer needed and will be removed from the RTEP

• 2013 RTEP modeling and analysis verified that they are no longer needed
• **Project Withdrawal**

• Cancel B1970: Reconductor 13 miles of the Kammer – West Bellaire 345kV

• Estimated Project Cost: $20M

• Projected IS Date: 6/1/2014
• **Project Withdrawal**

• Cancel B1976: Reconductor ATSI portion of South Canton – Harmon 345 kV line

• Estimated Project Cost: $6M

• Projected IS Date: 6/1/2015
• **Project Withdrawal**

  • Cancel B1926: Build a new Harmon – Brookside + Harmon - Longview 138 kV line

  • Estimated Project Cost: $9.2M

  • Projected IS Date: 6/1/2015
Short Circuit Upgrades
The Sporn 345 kV breakers ‘DD,’ ‘DD2,’ ‘AA2,’ ‘CC,’ ‘CC2,’ and ‘CC1,’ are overstressed.

Proposed Solution: Replace the Sporn 345 kV breakers ‘DD,’ ‘DD2,’ ‘AA2,’ ‘CC,’ ‘CC2,’ and ‘CC1,’ (b2378, b2379, b2383-b2385, b2394)

Estimated Project Cost: $1 M per breaker

Required IS Date: 6/1/2014
• The Muskingum River 345 kV breakers ‘SE,’ ‘SH,’ ‘S1,’ and ‘SG,’ are overstressed.

• Proposed Solution: Replace the Muskingum River 345 kV breakers ‘SE,’ ‘SH,’ ‘S1,’ and ‘SG,’ (b2380, b2387, b2388, b2390)

• Estimated Project Cost: $1 M per breaker

• Required IS Date: 6/1/2014
• The Weirton 138 kV breakers 'WYLIE RID210' and 'WYLIE RID216' are overstressed

• Proposed Solution: Replace the Weirton 138 kV breakers 'WYLIE RID210' and 'WYLIE RID216'. (b2424-b2425)

• Estimated Project Cost: $810k Per Breaker

• Required IS Date: 6/1/2018
• The Oak Grove 138 kV breakers 'OG1' 'OG2' 'OG3' 'OG4' 'OG5' and 'OG6' are overstressed

• Proposed Solution: Replace the Oak Grove 138 kV breakers 'OG1' 'OG2' 'OG3' 'OG4' 'OG5' and 'OG6'. (b2426-b2431)

• Estimated Project Cost: $810k Per Breaker

• Required IS Date: 6/1/2018
• The Ridgeley 138 kV breaker ‘RC1’ is overstressed

• Proposed Solution: Replace the Ridgeley 138 kV breaker ‘RC1’. (b2432)

• Estimated Project Cost: $810k Per Breaker

• Required IS Date: 6/1/2018
• The Pleasantview 230 kV breaker '203T274' is overstressed

• Proposed Solution: Replace the Pleasantview 230 kV breaker '203T274' with 63kA. (b2397-b2404)

• Estimated Project Cost: $272 K

• Required IS Date: 6/1/2018
- The Beaumeade 230 kV breakers '2079T2116' '2079T2130' '208192' '209592' '211692' '227T2130' '274T2130' and '227T2095' are overstressed.

- Proposed Solution: Replace the Beaumeade 230 kV breakers '2079T2116' '2079T2130' '208192' '209592' '211692' '227T2130' '274T2130' and '227T2095' with 63kA. (b2405)

- Estimated Project Cost: $272 K

- Required IS Date: 6/1/2018
Supplemental Upgrades
• Supplemental Project

  • Reconductor 13 miles of the Kammer – West Bellaire 345kV circuit. (S0645)
  
  • Estimated Cost: $20M
  
  • Projected IS Date: 06/1/2015
Supplemental Projects:
To improve reliability of the Mt. Washington area.

Proposed Solution:
- Install two 115 kV circuit breakers at Mt Washington substation (S0650).

Estimated Project Cost: $2.0 M

Expected IS Date: 6/1/2014
Supplemental Projects:
Potential local voltage collapse for the loss of the Gillette – Stirling 34.5 kV line.

Proposed Solution:
- Build a new 230/34.5 kV by tapping the Readington-Roseland 230 kV and connect the new station to Martinsville 34.5 kV substation (S0648).

Estimated Project Cost: $8.5 M
Expected IS Date: 6/1/2015
• Supplemental Projects:
  • Thermal overload on Chester 230/34.5 kV #1 transformer for the loss of the Chester – West Wharton 230 kV line with the tapped Chester #4 and West Wharton #2 transformers.

• Proposed Solution:
  - Upgrade the Chester 230/34.5 kV #1 transformer (S0649).

• Estimated Project Cost:
  $ 6.0 M

• Expected IS Date:
  6/1/2016
Supplemental Projects:

Overload on South Lebanon 230/69 kV #2 transformer for the loss of the South Lebanon 230/69 kV #1 transformer due to customer load increase.

Proposed Solution:
- North Lebanon substation: Install 2nd 230/69 kV transformer and 230 kV ring bus (S0647).

Estimated Project Cost: $11 M

Expected IS Date: 6/1/2015
• Supplemental Projects:
  • Improves reliability due to aging infrastructure.
• Proposed Solution:
  – Rebuild Martins Creek-Siegfried #2 230 kV Line- Phase 2 (S0642).
• Estimated Project Cost: $5.38 M
• Expected IS Date: 12/31/2014
PSE&G Transmission Zone - Northern NJ
Short Circuit
• PSEG Short Circuit Issue
  – 2012 RTEP identified several busses in PSEG zone where the fault currents exceed 80 kA
  – A number of alternatives evaluated including rebuilding stations to 90 kA standard, installing current limiting reactors, splitting the system, installing FCL (fault current limiters) technology
PJM evaluated alternative solutions

- Double circuit 345 kV Solution
  - Isolate Hudson 230 kV from the 138 kV at Marion and 345 kV at Farragut
  - Convert the 138 kV buses and transmission facilities on the path from Linden to Bergen to double circuit 345 kV

- Back to Back HVDC at Hudson

- Other solutions considered
  - Double circuit 230 kV Solution
    - Isolate Hudson 230 kV from the 138 kV at Marion and 345 kV at Farragut
    - Convert the 138 kV buses and transmission facilities on the path from Linden to Bergen to double circuit 230 kV
  - Other configurations
    - Transformer based fault current limiters

- Hudson #2 generation location assumption
  - Existing Hudson 230 kV or converted Marion 230 kV or 345 kV station?
• Double circuit 345 kV Solution

• Existing baseline projects included in the scope
• Recent stakeholder proposal to build parallel 700 MW HVDC converter stations

• Associated Stakeholder PJM queue request for 400 MW withdrawal from Hudson to New York
# Alternative Avoided Cost Summary

## Project Description

<table>
<thead>
<tr>
<th>Project Description</th>
<th>Project Status</th>
<th>PJM Project ID</th>
<th>Estimated Cost ($ M)</th>
<th>Subtotal Cost Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>345 kV Alternative</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reinforce Linden - PVSC Corridor - Reconfigure the Linden, Bayway, North Ave, and Passaic Valley Substations. Construct and loop new 138 kV circuit to new airport station. Install 230/138 kV transformer at Bergen substation. Rebuild 2.19 miles of overhead line E-1305-5 (Bergen - North Bergen).</td>
<td>Baseline - Approved</td>
<td>b2159</td>
<td>250</td>
<td>325.50</td>
</tr>
<tr>
<td>Reconfigure Marion for Breaker and Half. Build for 230 kV, operate at 138 kV with 80 kA breakers.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reconnector of PVSC - Bayonne Circuit.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Build a parallel Stanley Terrace - McCarter.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Build a parallel K-2211-7 circuit (Aldene - StanleyTce).</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Build a parallel McCarter - West Orange.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Build a parallel G-2285 (Aldene - SpringfieldRd).</td>
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</tr>
<tr>
<td>Upgrade U-2273 (VFT - Waringcono)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upgrade N-2240 (Waringcono - Aldene)</td>
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<td></td>
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</tr>
<tr>
<td>Upgrade S-2271 (Tosco - VFT)</td>
<td></td>
<td>me0316</td>
<td>150</td>
<td>150</td>
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<tr>
<td>Upgrade B-2254 (Tosco - Linden)</td>
<td></td>
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<td></td>
</tr>
<tr>
<td><strong>TOTAL AVOIDED COST - 345 kV Solution Alternative</strong></td>
<td></td>
<td></td>
<td>$(1,040.42)</td>
<td></td>
</tr>
<tr>
<td><strong>HVDC Alternative</strong></td>
<td></td>
<td>me0316</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>No anticipated avoided cost impact to RTEP, all projects and associated costs above would be required in addition to the estimated HVDC base project cost.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL AVOIDED COST - HVDC Solution Alternative</strong></td>
<td></td>
<td>me0316</td>
<td>150</td>
<td>150</td>
</tr>
</tbody>
</table>

* Based on most recent cost estimates.
## Alternative Cost Comparison

*Based on preliminary information from engineering review*

<table>
<thead>
<tr>
<th>Project Description</th>
<th>Estimated Cost ($M)</th>
<th>Subtotal Cost Estimate ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>345 kV Solution Alternative</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base Project Cost</td>
<td>$874.30</td>
<td></td>
</tr>
<tr>
<td>Risk &amp; Contingency (35% assumption)</td>
<td>$306.00</td>
<td></td>
</tr>
<tr>
<td>Reconfigure Hudson 2 to inject into 345 kV at Marion</td>
<td>$20.00</td>
<td>$1,200.30</td>
</tr>
<tr>
<td>Avoided Cost</td>
<td></td>
<td>$1,040.42</td>
</tr>
<tr>
<td><strong>Total Net Overall Project Cost Impact to RTEP</strong></td>
<td></td>
<td><strong>159.88</strong></td>
</tr>
<tr>
<td><strong>HVDC Solution Alternative</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base Project Cost</td>
<td>$481.00</td>
<td></td>
</tr>
<tr>
<td>Base Project Risk &amp; Contingency (19% assumption)</td>
<td>$91.39</td>
<td></td>
</tr>
<tr>
<td>Reconfigure Hudson 2 to inject into 345 kV on NY side of HVDC</td>
<td>$35.00</td>
<td>$614.39</td>
</tr>
<tr>
<td>Hudson 2 move Risk &amp; Contingency (20% assumption)</td>
<td>$7.00</td>
<td></td>
</tr>
<tr>
<td>Avoided Cost</td>
<td>$614.39</td>
<td>$614.39</td>
</tr>
<tr>
<td><strong>Total Net Overall Project Cost Impact to RTEP</strong></td>
<td>$614.39</td>
<td></td>
</tr>
</tbody>
</table>
Constructability Review Update

- Independent consultant - Burns & Roe

- Scope
  - HVDC and 345 kV Double Circuit Alternatives

- Deliverables
  - Validate costs, schedules, identify risk areas

- Draft report

- Findings consistent with today’s discussion
<table>
<thead>
<tr>
<th>Constructability Review Summary*</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Double Circuit 345kV</strong></td>
</tr>
<tr>
<td>Total Overall RTEP Cost</td>
</tr>
<tr>
<td>- 48 months</td>
</tr>
<tr>
<td>- Project will be completed in phases</td>
</tr>
<tr>
<td>Anticipated Schedule</td>
</tr>
<tr>
<td>ROW Acquisition</td>
</tr>
<tr>
<td>- Overhead facilities will use existing ROW</td>
</tr>
<tr>
<td>- Underground/underwater facilities will need new ROW adjacent to existing ROW</td>
</tr>
<tr>
<td>Land Acquisition</td>
</tr>
<tr>
<td>Additional land required to expand several substation sites</td>
</tr>
<tr>
<td>Siting / Permitting</td>
</tr>
<tr>
<td>Permitting considered feasible within projected schedule</td>
</tr>
<tr>
<td>Project Complexity</td>
</tr>
<tr>
<td>- Requires modifications at several substation sites</td>
</tr>
<tr>
<td>- Work involves construction in congested areas</td>
</tr>
<tr>
<td>- Rebuild along existing overhead corridors requires outages and design considerations</td>
</tr>
<tr>
<td>Staging</td>
</tr>
<tr>
<td>- Staging considered feasible. Staging plan to be finalized during the design phase</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td><strong>Back to back HVDC</strong></td>
</tr>
<tr>
<td>Total Overall RTEP Cost Impact to R Ted $159.88</td>
</tr>
<tr>
<td><strong>HVDC project cost - $614.39</strong></td>
</tr>
<tr>
<td><strong>Avoided Cost - $0</strong></td>
</tr>
<tr>
<td><strong>Total Overall Cost Impact to R Ted $614.39</strong></td>
</tr>
<tr>
<td>ROW Acquisition</td>
</tr>
<tr>
<td>Minimal new ROW</td>
</tr>
<tr>
<td>Land Acquisition</td>
</tr>
<tr>
<td>Land required for Back-to-back HVDC facility and substation</td>
</tr>
<tr>
<td>Siting / Permitting</td>
</tr>
<tr>
<td>Proposed site is classified wetland with potential schedule impact in permitting</td>
</tr>
<tr>
<td>Project Complexity</td>
</tr>
<tr>
<td>- Requires modifications at one substation and site</td>
</tr>
<tr>
<td>- Work involves construction in congested area</td>
</tr>
<tr>
<td>Staging</td>
</tr>
<tr>
<td>Staging considered feasible</td>
</tr>
</tbody>
</table>

* Based on preliminary information from engineering review
• Recommendation

– Anticipate recommending the Double Circuit 345 kV alternative, contingent on final constructability review, to the PJM Board at the scheduled December Board meeting
Next Steps

- Review draft constructability report and finalize the report

- Schedule special PC teleconference in late November 2013, prior to the December 2013 PJM Board meeting, to review the final report findings

- Continue NYISO coordination
Deactivation Analysis Update
<table>
<thead>
<tr>
<th>Unit(s)</th>
<th>Transmission Zone</th>
<th>Requested Deactivation Date</th>
<th>PJM Reliability Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mad River CTs A &amp; B (50MWs – no CIRs)</td>
<td>ATSI</td>
<td>1/9/2014</td>
<td>Reliability Analysis underway</td>
</tr>
<tr>
<td>Muskingum River 5 (600MWs)</td>
<td>AEP</td>
<td>6/1/2015</td>
<td>Reliability Analysis underway</td>
</tr>
<tr>
<td>Tanners Creek 4 (500MWs)</td>
<td>AEP</td>
<td>6/1/2015</td>
<td>Reliability Analysis underway</td>
</tr>
<tr>
<td>Sunbury (94MWs)</td>
<td>PPL</td>
<td>4/13/2015</td>
<td>Reliability Analysis underway</td>
</tr>
</tbody>
</table>
Artificial Island RTEP Proposal Window
Artificial Island Proposal Window Status

- Window opened on 4/29/2013
- Closed on 6/28/2013

- 26 individual proposals
- 7 entities

- Project Naming Convention
- Project Identification Taxonomy: 2013_1-1A
Artificial Island Proposal Window Timeline

**Announcement**
- Announce window and potential timeline
- Request CEII/NDA submittals from anticipated participants
- Request Designated Entity Pre-Qualification

**PSS/E v32 Case Development**
- Initial PSS/E v32 case created
- Benchmarking in Progress
- Develop and benchmark critical system condition cases

**Window Opened**
- (4/29/2013 - 60 Day Duration)
- Open the "Artificial Island" RTEP Proposal Window
- Complete problem statement available
- Analytical files available

**Proposal Window Closed on**
- 6/28/2013

**PJM Evaluates Solution Proposals**

**Coordinate with Window Participants and Receive Solution Proposals**
- Coordination VIA www.pjm.com
- Data, Information
- Questions & Answers
### Artificial Island Proposals

<table>
<thead>
<tr>
<th>Project ID</th>
<th>TO</th>
<th>Cost ($)</th>
<th>Major Components</th>
<th>Supporting info</th>
</tr>
</thead>
<tbody>
<tr>
<td>P2011_11B</td>
<td>Virginia Electric and Power Comm</td>
<td>$123</td>
<td>New 500 kV from Salem - new station in Delaware</td>
<td>New 500 kV SVC station in Delaware that taps existing Cedar Creek - Red Lion 230 kV and Carters - Red Lion 230 kV</td>
</tr>
<tr>
<td>P2011_11C</td>
<td>Virginia Electric and Power Comm</td>
<td>$202</td>
<td>New 500 kV from Hope Creek - a new station in Delaware</td>
<td>Install a new 500 kV line from Hope Creek to Red Lion; New Salem - Hope Creek 500 kV line</td>
</tr>
<tr>
<td>P2011_2A</td>
<td>Transource</td>
<td>$280</td>
<td>Salem - Cedar Creek 230 kV</td>
<td>Two (2) 500 kV Transformers near Salem, Loop in Red Lion - Carters 210 to Cedar Creek</td>
</tr>
<tr>
<td>P2011_2B</td>
<td>Transource</td>
<td>$185</td>
<td>Salem - North Cedar Creek (new) 230 kV</td>
<td>Two (2) 500 kV Transformers near Salem and loop in Red Lion - Carters 210 and Red Lion - Cedar Creek 230 kV</td>
</tr>
<tr>
<td>P2011_2C</td>
<td>Transource</td>
<td>$223</td>
<td>Salem - Red Lion 500 kV</td>
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<tr>
<td>P2011_2D</td>
<td>Transource</td>
<td>$788</td>
<td>New Freedom - Lumberton - North Smithburg (New) 500 kV line</td>
<td>New Salem - Hope Creek 500 kV line and new 500 kV station east of Lumberton</td>
</tr>
<tr>
<td>P2011_3A</td>
<td>FirstEnergy</td>
<td>$410.7</td>
<td>New Freedom - Smithburg 500 kV line with a loop into Lumberton</td>
<td>Hope Creek - Red Lion 500 kV line</td>
</tr>
<tr>
<td>P2011_4A</td>
<td>PHI Edison</td>
<td>$475</td>
<td>Peru - Bottom - Kenney - Red Lion - Salem 500 kV</td>
<td>Remove Kenney - Red Lion 230 kV, Reconfigure 230 around Hay Field, Reconductor Harmony Chapel St 130 kV</td>
</tr>
<tr>
<td>P2011_6A</td>
<td>LG Power</td>
<td>$150.34</td>
<td>Salem - Silver Run (new) 200 kV, Salem 500 x 200 kV Transformer</td>
<td>New 200 kV station that taps existing Cedar Creek - Red Lion 230 kV and Carters - Red Lion 230 kV</td>
</tr>
<tr>
<td>P2011_6B</td>
<td>LG Power</td>
<td>$970</td>
<td>Salem - Red Lion 500 kV</td>
<td></td>
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<tr>
<td>P2011_6C</td>
<td>Atlantic Wind</td>
<td>$1012</td>
<td>330 kV HVAC Salem to Hope Creek to Cardiff</td>
<td>SVC at Salem - Hope Creek, New HVAC Stations at Cardiff and Salem</td>
</tr>
<tr>
<td>P2011_7A</td>
<td>PSEG</td>
<td>$1271</td>
<td>Salem-Hope Creek to Peru Bottom 500 kV</td>
<td>Existing PCN</td>
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<tr>
<td>P2011_7B</td>
<td>PSEG</td>
<td>$1272</td>
<td>Salem-Hope Creek to Peru Bottom 500 kV</td>
<td>Same as 7A with Loop into Kenney</td>
</tr>
<tr>
<td>P2011_7C</td>
<td>PSEG</td>
<td>$1272</td>
<td>Salem-Hope Creek to Peru Bottom 500 kV</td>
<td>Same as 7A with Loop into Kenney</td>
</tr>
<tr>
<td>P2011_7D</td>
<td>PSEG</td>
<td>$639</td>
<td>New Freedom - Drainage 500 kV, Salem - Hope Creek 500 kV lines</td>
<td>Same as 7A with New PCN</td>
</tr>
<tr>
<td>P2011_7E</td>
<td>PSEG</td>
<td>$973</td>
<td>New Freedom - Smithburg and Salem - Hope Creek, 600 kV lines</td>
<td>Existing PCN</td>
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<tr>
<td>P2011_7F</td>
<td>PSEG</td>
<td>$1031</td>
<td>New Freedom - Smithburg and Salem - Hope Creek 600 kV lines</td>
<td>Same as 7F with Loop into a new Lebanon 500 kV station</td>
</tr>
<tr>
<td>P2011_7G</td>
<td>PSEG</td>
<td>$1977</td>
<td>New Freedom - Vidginian and Salem - Hope Creek 500 kV lines</td>
<td>Northern Route</td>
</tr>
<tr>
<td>P2011_7H</td>
<td>PSEG</td>
<td>$1363</td>
<td>New Freedom - Vidginian and Salem - Hope Creek 500 kV lines</td>
<td>Same as 7H with the Southern Route</td>
</tr>
<tr>
<td>P2011_7I</td>
<td>PSEG</td>
<td>$1915</td>
<td>New Freedom - New Station on Branchburg Ellicott 500 kV line (&quot;Sidetalk&quot;) and Salem - Hope Creek 500 kV line</td>
<td>Existing PCN</td>
</tr>
<tr>
<td>P2011_7J</td>
<td>PSEG</td>
<td>$1668</td>
<td>New Freedom - Drainage 500 kV line to Hope Creek, Red Lion 600 kV</td>
<td>Same as 7E with Hope Creek - Red Lion</td>
</tr>
<tr>
<td>P2011_7K</td>
<td>PSEG</td>
<td>$1250</td>
<td>New Freedom - Smithburg - Salem - Hope Creek, 600 kV lines</td>
<td>Same as 7E with Hope Creek - Red Lion</td>
</tr>
<tr>
<td>P2011_7L</td>
<td>PSEG</td>
<td>$1548</td>
<td>New Freedom - Vidginian (North) - Salem - Hope Creek, Red Lion 500 kV line to Hope Creek - Red Lion</td>
<td>Same as 7H with Hope Creek - Red Lion</td>
</tr>
<tr>
<td>P2011_7M</td>
<td>PSEG</td>
<td>$1289</td>
<td>New Freedom - a new Station on the Branchburg-Ellicott 500 kV line (&quot;Sidetalk&quot;) in Salem - Hope Creek, Red Lion 500 kV line</td>
<td>Same as 7H with Hope Creek - Red Lion</td>
</tr>
</tbody>
</table>
• Overall approach
  – Assess physical project characteristics
    • Feasibility, cost, etc.
    • Evaluate projects in the lower range of expected total cost first
  – Analytic simulation performance
    • Development and use of methods to compare performance of proposals
    • Performance trend
• Evaluations of project constructability/cost AND performance underway
  – Constructability and cost evaluation
    • Currently underway by several independent consultants
  – Performance
    • PJM is analyzing the effectiveness of elements of, or entire transmission proposals combined with and without SVCs at several proposed locations
1. Evaluate the 230 kV alternatives from the Artificial Island to the Delmarva Peninsula (including SVC sensitivity)
   • Review Today

2. Evaluate Artificial Island – Red Lion 500 kV alternatives (including SVC sensitivity)
   • Analysis Underway

3. Continue to evaluate Artificial Island project submissions
   • Analyze if feasible solution not found above
• P2013_1-1A
  – SVC @ New Freedom + two Thyristor Controlled Series Compensation (TCSC) devices near New Freedom
  – Estimated by project sponsor at $133 M
• Project characteristics
  – Device response
  – No new physical outlet from the Artificial Island
• Performance
  – Did not pass testing criteria even with an SVC
• Next Steps
  – Evaluate the TCSC further if transmission alternatives do not meet performance requirements
  – Continue to evaluate the SVC at New Freedom in combination with transmission solutions
• Submitted by LS Power
• Install a new Salem 500/230 kV transformer
• Establish a new Silver Run 230 kV station that taps Red Lion – Cartanza 230 kV and Red Lion – Cedar Creek 230 kV
• Install a new 230 kV circuit from Salem to the new Silver Run 230 kV station
• Submitted by Transource
• Install (2) 500/230 kV transformers near Salem
• Establish a new North Cedar Creek 230 kV station and loop in Red Lion – Cartanza 230 kV and Red Lion – Cedar Creek 230 kV
• Install a 230 kV circuit from Salem to the new North Cedar Creek 230 kV
• Submitted by Transource
• Install (2) 500/230 kV transformers near Salem
• Install a 230 kV circuit from Salem to Cedar Creek 230 kV (existing)
• Submitted by Virginia Electric and Power Company
• Establish a new Delaware 500/230 kV station that taps Red Lion – Cartanza 230 kV and Red Lion – Cedar Creek 230 kV
  – Install two parallel 500/230 kV transformers at the new Delaware station
• Install a new 500 kV line from Salem to the new station in Delaware
Artificial Island – Red Lion 500 kV Proposals

- New Artificial Island to Red Lion 500 kV
- Submitted in several variations by several entities
  - Artificial Island connection
  - Red Lion connection
  - River Crossing
• SVC locations that were submitted during the AI window
  – Near the Artificial Island
  – Orchard 500 kV
  – New Freedom 500 kV
Artificial Island Analytical Evaluation

• System Performance
  – Overall improvement
  – Individual performance comparison

• Comparison Methods

• Performance measurements
Artificial Island Analytical Evaluation
Comparison Methods

• 230 kV Transmission Solutions
  – Assuming the same AI Voltage, observe the AI MVAr output and maximum angle swing
    • Less AI MVAr output means more MVAr margin.
    • Less angle swing correlates to a larger stability margin
  – Given the same AI MVAr output compare the maximum angle swing
    • Less angle swing correlates to a larger stability margin

• SVC Locations
  – Evaluate the effectiveness of the SVC locations by observing AI MVAr output and maximum angle swing
    • Less angle swing correlates to a larger stability margin
**Comparison Method:**
Assume 1.065 p.u. at the AI (unstable below 1.065), solve the power flow for the corresponding Salem and Hope Creek MVAr output. Simulate the combination of the most critical fault and outage. Do not assume the addition of an SVC.

**Result:**
Measure the maximum machine angle swing.
All 230 kV proposals pass the stability criteria.

<table>
<thead>
<tr>
<th>Group</th>
<th>Project ID</th>
<th>230 kV Transmission Solution</th>
<th>AI 500kV bus voltage</th>
<th>AI MVAr output</th>
<th>Critical Outage</th>
<th>Critical Contingency</th>
<th>Maximum Angle Swing (deg.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1</td>
<td>P2013_1-5A</td>
<td>LS Power</td>
<td>1.065 pu</td>
<td>1044</td>
<td>5015*</td>
<td>14b**</td>
<td>102</td>
</tr>
<tr>
<td>1.1</td>
<td>P2013_1-2B</td>
<td>Transource (AEP)</td>
<td>1.065 pu</td>
<td>965</td>
<td>5015</td>
<td>14b</td>
<td>105</td>
</tr>
<tr>
<td>1.1</td>
<td>P2013_1-2A</td>
<td>Transource (AEP)</td>
<td>1.065 pu</td>
<td>940</td>
<td>5015</td>
<td>14b</td>
<td>110</td>
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<tr>
<td>1.2</td>
<td>P2013_1-1B</td>
<td>DVP</td>
<td>1.065 pu</td>
<td>926</td>
<td>5015</td>
<td>14b</td>
<td>115</td>
</tr>
</tbody>
</table>

5015*: Hope Creek – Red Lion 500kV line
14b**: single-line-to-ground fault on the new line from Salem w/ delayed clearing due to stuck breaker
Comparison Method:
For each proposal, assume a fixed MVAr output at the Artificial Island, solve the power flow for the corresponding Artificial Island bus voltages. Simulate the combination of the most critical fault and outage. Do not assume the addition of an SVC.

Result:
Measure the maximum machine angle swing. All 230 kV proposal pass the stability criteria.

<table>
<thead>
<tr>
<th>Group</th>
<th>Project ID</th>
<th>230 kV Transmission Solution</th>
<th>AI 500kV bus voltage</th>
<th>AI MVAr output</th>
<th>Critical Outage</th>
<th>Critical Contingency</th>
<th>Maximum Angle Swing (deg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1</td>
<td>P2013_1-5A</td>
<td>LS Power</td>
<td>1.065</td>
<td>1044</td>
<td>5015</td>
<td>14b</td>
<td>102</td>
</tr>
<tr>
<td>1.1</td>
<td>P2013_1-2B</td>
<td>Transource (AEP)</td>
<td>1.071</td>
<td>1044</td>
<td>5015</td>
<td>14b</td>
<td>95</td>
</tr>
<tr>
<td>1.1</td>
<td>P2013_1-2A</td>
<td>Transource (AEP)</td>
<td>1.074</td>
<td>1044</td>
<td>5015</td>
<td>14b</td>
<td>95</td>
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<tr>
<td>1.2</td>
<td>P2013_1-1B</td>
<td>DVP</td>
<td>1.074</td>
<td>1044</td>
<td>5015</td>
<td>14b</td>
<td>97</td>
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</tbody>
</table>

5015*: Hope Creek – Red Lion 500kV line
14b**: single-line-to-ground fault on the new line from Salem w/ delayed clearing due to stuck breaker
Comparison Method:
For each proposal, assume a fixed MVAr output at the Artificial Island, solve the power flow for the corresponding Artificial Island bus voltages. Simulate the combination of the most critical fault and outage. Do not assume the addition of an SVC.

Result:
Measure the maximum machine angle swing.
All 230 kV proposal pass the stability criteria.

<table>
<thead>
<tr>
<th>Group</th>
<th>Project ID</th>
<th>230 kV Transmission Solution</th>
<th>AI 500kV bus voltage</th>
<th>AI MVAr output</th>
<th>Critical Outage</th>
<th>Critical Contingency</th>
<th>Maximum Angle Swing (deg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1</td>
<td>P2013_1-5A</td>
<td>LS Power</td>
<td>1.044</td>
<td>832</td>
<td>5038*</td>
<td>2b**</td>
<td>121</td>
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<tr>
<td>1.1</td>
<td>P2013_1-2B</td>
<td>Transource (AEP)</td>
<td>1.052</td>
<td>832</td>
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<td>89</td>
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<tr>
<td>1.1</td>
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<td>Transource (AEP)</td>
<td>1.053</td>
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<td>5038</td>
<td>2b</td>
<td>93</td>
</tr>
<tr>
<td>1.2</td>
<td>P2013_1-1B</td>
<td>DVP</td>
<td>1.049</td>
<td>832</td>
<td>5038</td>
<td>2b</td>
<td>87</td>
</tr>
</tbody>
</table>

5038*: New Freedom – East Windsor 500kV line
2b**: single-line-to-ground fault on Hope Creek-Red Lion 500kV line w/ delayed clearing due to stuck breaker
Comparison Method:
For each proposal, assume the addition of an SVC at each of three locations. Simulate the combination of the most critical fault and outage.

Result:
Measure the maximum machine angle swing.
All 230 kV proposals with SVC additions pass the stability criteria with greater margin than without SVCs.

<table>
<thead>
<tr>
<th>Project ID</th>
<th>230 kV Transmission Solution</th>
<th>SVC option</th>
<th>Al 500kV Bus Voltage</th>
<th>Al MVAr Output</th>
<th>Critical Outage</th>
<th>Critical Contingency</th>
<th>Maximum Angle Swing</th>
</tr>
</thead>
<tbody>
<tr>
<td>P2013_1-5A-SVC</td>
<td>LS Power</td>
<td>Artificial Island</td>
<td>1.042</td>
<td>728</td>
<td>5015</td>
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<td>80</td>
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<td></td>
<td></td>
<td>Orchard</td>
<td>1.041</td>
<td>724</td>
<td>5015</td>
<td>14b</td>
<td>108</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New Freedom</td>
<td>1.041</td>
<td>721</td>
<td>5015</td>
<td>14b</td>
<td>112</td>
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<td>P2013_1-2B-SVC</td>
<td>Transource (AEP)</td>
<td>Artificial Island</td>
<td>1.042</td>
<td>664</td>
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<tr>
<td></td>
<td></td>
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<td>1.042</td>
<td>662</td>
<td>5015</td>
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<tr>
<td></td>
<td></td>
<td>New Freedom</td>
<td>1.042</td>
<td>662</td>
<td>5015</td>
<td>14b</td>
<td>109</td>
</tr>
<tr>
<td>P2013_1-2A-SVC</td>
<td>Transource (AEP)</td>
<td>Artificial Island</td>
<td>1.043</td>
<td>655</td>
<td>5015</td>
<td>14b</td>
<td>82</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Orchard</td>
<td>1.042</td>
<td>658</td>
<td>5015</td>
<td>14b</td>
<td>107</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New Freedom</td>
<td>1.042</td>
<td>658</td>
<td>5015</td>
<td>14b</td>
<td>112</td>
</tr>
<tr>
<td>P2013_1-1B-SVC</td>
<td>DVP</td>
<td>Artificial Island</td>
<td>1.042</td>
<td>672</td>
<td>5015</td>
<td>14b</td>
<td>85</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Orchard</td>
<td>1.041</td>
<td>670</td>
<td>5015</td>
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<td>106</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New Freedom</td>
<td>1.041</td>
<td>674</td>
<td>5015</td>
<td>14b</td>
<td>110</td>
</tr>
</tbody>
</table>

Note: The study results are obtained under the assumption of unity power factor at the high side of GSU.
Artificial Island Evaluation – Preliminary Observations

- **230 kV Proposal Summary (no SVC)**
  - 230kV proposals pass stability criteria under the assumption of 1.065pu at the Artificial Island
  - P2013_1-1B (Virginia Electric and Power Company) and P2013_1-2B (Transource) and P2013_1-2A (Transource) demonstrate greater margin than the P2013_1-5A (LS Power) proposal

- **230 kV Proposal Summary (combined with SVC)**
  - Compared to the simulations without an SVC
    - Lowers the bus voltage and machine MVAR requirements at the AI
    - Reduces the maximum machine angle swing, especially with the SVC located near the AI
  - Demonstrate greater margin than 230kV without SVC options
  - All three SVC locations are beneficial, the Artificial Island SVC location demonstrates better performance than the other two locations
• Next Steps
  – Evaluate Artificial Island – Red Lion 500 kV alternatives (including SVC sensitivity)
  – Continue thermal and voltage analysis
Artificial Island – Constructability Analysis

- Scope
- Progress
  - Data request to project sponsors for supplemental constructability review
  - Work underway
- Approach & Deliverables
  - Evaluate costs and schedules of major similarities and differences between proposals
  - Validate costs, schedules, identify risk areas
  - Identify potential alternatives
- Timeline
  - Complete in 2013
Conceptual Artificial Island Schedule

- September 12\textsuperscript{th} TEAC
  - Update analytical progress
- October 10\textsuperscript{th} TEAC
  - Update analytical progress
  - Update feasibility study progress
- November 7\textsuperscript{th} TEAC
  - Update analytical progress
  - Update feasibility study progress
- December 11\textsuperscript{th} TEAC
  - Update feasibility study progress
- January – February 2014
  - Recommend solution to TEAC
- 2014
  - Recommend solution to PJM Board
Recommendations to PJM Board in December
2013
• This is the second request for PJM Board approval of the RTEP in 2013
  – Includes SRRTEP reliability projects reviewed at November 2013 SRRTEP meetings
  – Includes TEAC reliability projects reviewed 10/2012 through 11/2013 (today)
• The PJM Board will be requested to approve projects in this section of the presentation for inclusion in the RTEP
• **Cost Change for B2354**
  Install second 230/69kV transformer and 230kV circuit breaker at Churchtown substation (b2354)

• **Estimated Project Cost:**
  Previous → $3.5 M
  New → $8.6 M

• **Expected IS Date:**
  6/1/2015
Scope Change for B2220:

- Previous Scope: Install four 115 kV breakers at Chestnut Hill.
- New Scope: Install two 115 kV breakers at Chestnut Hill and remove sag limitations on the Pumphrey - Frederick Rd 115kV circuits 110527 and 110528 to obtain a $125^0C$ rating (161/210 MVA).

- Estimated Project Cost: $6.4 M
- Expected IS Date: 6/1/2017
- Cancel/Replace B1267, B1267.1, B1267.2, and B1267.3 upgrades:
- The B1267.1 (Construct 115 kV double circuit underground line from existing Cold Spring to Erdman substation) and B1267 (Rebuild existing Erdman 115 kV substation to a dual ring-bus configuration to enable termination of new circuits) will be canceled and replaced with the following upgrade.
  - New Proposed Solution:
    - Install a tie breaker at Mays Chapel 115 kV substation. Build a new Camp Small 115 kV station and install 30 MVAR capacitor (B2396).
  - Estimated Project Cost: $18 M
  - Expected IS Date: 6/1/2018
- Cancel B1606.1 and B1606.2 upgrades:
- The B1606.1 (Moving the station supply connections of the Hazelwood 115/13kV station) and B1606.2 (Installing 115kV tie breakers at Melvale) will be canceled and replaced with B2396 (Install a tie breaker at Mays Chapel 115 substation. Build a new Camp Small 115 kV station and install 30 MVAR capacitor).
• **N-1-1 Analysis:**
  • The Harmony - Chapel St 138 kV circuit is overloaded for several N-1-1 contingencies.

• **Proposed Solution:**
  – Reconduct the Harmony - Chapel St 138 kV circuit (B2395).

• **Estimated Project Cost:**
  – $1.62 M

• **Expected IS Date:**
  – 6/1/2018
• The Eddystone 138 kV breakers breakers #205 and #415 are overstressed

• Significant Driver: Install a second Eddystone 230/138 kV transformer

• Proposed Solution: Increase the rating of the Eddystone 138kV breakers #205 and #415 (b2222.1 – b2222.2)

• Estimated Project Cost: $500 K

• Required IS Date: 6/1/2017
PPL Transmission Zone

- **PPL Criteria Violation:**
  - The Jenkins-Scranton #1 & #2 69kV lines are loaded above 60% of capacity, resulting in a load loss of greater than 120MW for a double-circuit outage of the Jenkins-Scranton #1 & #2 69 kV circuits

- **Proposed Solution:**
  - The upgrades are in the following slide.

- **Estimated Project Cost:**
  - $68.6 M

- **Expected IS Date:**
  - 11/30/2017
<table>
<thead>
<tr>
<th>Upgrade ID</th>
<th>Upgrade Description</th>
<th>Expected IS date</th>
<th>Estimated Project Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>B2406.1</td>
<td>Rebuild Stanton-Providence 69 kV 2&amp;3 9.5 miles with 795 SCSR</td>
<td>11/30/2017</td>
<td>20.5</td>
</tr>
<tr>
<td>B2406.2</td>
<td>Reconduct 7 miles of the Lackawanna-Providence #1 &amp; #2 69 kV with 795 ACSR</td>
<td>11/30/2017</td>
<td>15.1</td>
</tr>
<tr>
<td>B2406.3</td>
<td>Rebuild SUB2 Tap 1 (Lackawanna-Scranton 1) 69 kV 1.5 miles 556 ACSR</td>
<td>11/30/2017</td>
<td>1.5</td>
</tr>
<tr>
<td>B2406.4</td>
<td>Rebuild SUB2 Tap 2 Lackawanna-Scranton 2) 69 kV 1.6 miles 556 ACSR</td>
<td>11/30/2017</td>
<td>1.6</td>
</tr>
<tr>
<td>B2406.5</td>
<td>Create Providence - Scranton 69 kV 1&amp;2, 3.5 miles 795 ACSR</td>
<td>11/30/2017</td>
<td>3.9</td>
</tr>
<tr>
<td>B2406.6</td>
<td>Rebuild Providence 69 kV Switchyard</td>
<td>11/30/2017</td>
<td>4</td>
</tr>
<tr>
<td>B2406.7</td>
<td>Install 2 - 10.8 MVAR Caps at EYNO 69 kV</td>
<td>11/30/2017</td>
<td>2</td>
</tr>
<tr>
<td>B2406.8</td>
<td>Rebuild Stanton 230 kV yard</td>
<td>11/30/2017</td>
<td>20</td>
</tr>
</tbody>
</table>
## PPL Canceled Upgrades

<table>
<thead>
<tr>
<th>Upgrade ID</th>
<th>Description</th>
<th>Reason for Cancelation</th>
</tr>
</thead>
<tbody>
<tr>
<td>b1767</td>
<td>Install 6 motor-operated disconnect switches at Quarry substation</td>
<td>Recent analysis showed need for switches has been deferred. A new baseline project will be submitted in the future for Quarry Substation upgrades that will include this switch installation.</td>
</tr>
<tr>
<td>b1891</td>
<td>Build a new 230/138 kV Yard at Lackawanna (138 kV conversion from Lackawanna to Jenkins)</td>
<td>138kV conversion projects are being changed to a more economical solution of rebuilding existing 69 kV circuits to higher capacity in and around the greater Scranton area.</td>
</tr>
<tr>
<td>b1892</td>
<td>Rebuild the Throop Taps for 138 kV operation (138 kV Conversion from Lackawanna to Jenkins)</td>
<td>138kV conversion projects are being changed to a more economical solution of rebuilding existing 69 kV circuits to higher capacity in and around the greater Scranton area.</td>
</tr>
<tr>
<td>b1897</td>
<td>Build a new 230/138 kV substation at Jenkins (138 kV Conversion from Lackawanna to Jenkins)</td>
<td>138kV conversion projects are being changed to a more economical solution of rebuilding existing 69 kV circuits to higher capacity in and around the greater Scranton area.</td>
</tr>
<tr>
<td>s0062</td>
<td>Conestoga Substation: Upgrade Relay and Control Equipment</td>
<td>Conestoga Substation is a Distribution substation only and will not need to be presented before the SRRTEP or TEAC.</td>
</tr>
<tr>
<td>s0529</td>
<td>Build a new Trumbauersville 69/12 kV substation by tapping the Buxmont - Springfield 69 kV line</td>
<td>This is a duplicate of s0347 which is the 69 kV Tap to the new Trumbauersville Substation.</td>
</tr>
<tr>
<td>s0531</td>
<td>Build a new Factoryville 69/12 kV substation by tapping the Martins Creek - Nazareth #3 69 kV line</td>
<td>This is a duplicate of s0348 which is the 69 kV Tap to the new Factoryville Substation.</td>
</tr>
<tr>
<td>Upgrade ID</td>
<td>Description</td>
<td>New Description</td>
</tr>
<tr>
<td>-----------</td>
<td>--------------------------------------------------</td>
<td>------------------------------------------------------</td>
</tr>
<tr>
<td>s0416</td>
<td>New 69 kV Tap to West Hershey 69/13.2 kV substation</td>
<td>New 69 kV tap to Cocoa 69/13.2 kV substation</td>
</tr>
<tr>
<td>b1894</td>
<td>Rebuild and re-conductor 2.5 miles of the Stanton - Avoca 69 kV line</td>
<td>Rebuild and re-conductor 8.1 miles of the Stanton - Avoca 69 kV line</td>
</tr>
<tr>
<td>b1896</td>
<td>Install 69 kV capacitor at North Stroudsburg 69/12 kV Substation</td>
<td>Install 138 kV capacitor at North Stroudsburg 138/12 kV Substation</td>
</tr>
<tr>
<td>s0539</td>
<td>Modify 69 kV tap to convert to modified Twin A operation</td>
<td>Lincoln 69-12 kV Substation: Convert to Modified Twin A</td>
</tr>
</tbody>
</table>
- **Basecase Category C:**
  - Voltage magnitude and voltage drop violation at Front St., Plainfield and South Second St. for several category C contingencies.

- **Proposed Solution:**
  - Install all 69kV lines to interconnect Plainfield, Greenbrook, and Bridgewater stations and establish the 69kV network.
  - Install two 18MVAR capacitors at Plainfield and S. Second St substation.
  - Install a second four (4) breaker 69kV ring bus at Bridgewater Switching Station (B2421).

- **Estimated Project Cost:**
  - $41.94 M

- **Expected IS Date:**
  - 6/1/2018
• **Light Load Reliability Analysis**

• The Bearskin - Smith Mountain 138kV line is overloaded due to various single contingencies

• Proposed Solution: Change the existing CT ratios of the existing equipment along Bearskin - Smith Mountain 138kV circuit (B2374)

• Estimated Project Cost: $0.6M

• Required IS Date: 3/1/2015
- **Light Load Reliability Analysis**

- The East Danville-Banister 138kV line is overloaded due to various single contingencies

- Proposed Solution: Change the existing CT ratios of the existing equipment along East Danville-Banister 138kV circuit (B2375)

- Estimated Project Cost: $0.6M

- Required IS Date: 3/1/2015
• **N-1-1 Voltage Violation**

  Voltage drop violations at Fremont, Tiffin, and neighboring 138kV buses for various contingency pairs

  • Install two 56.4 MVAr Capacitor banks at the Melmore 138 kV station in Ohio (B2409)

  • Estimated Cost: $1.5M

  • Required IS Date: 6/1/2018
• **N-1-1 Voltage Violation**

  Local voltage collapse of the 138 kV system in Alexandria area (Mullin, Strawton, Elwood and surrounding buses) for various N-1-1 contingency pairs

  Convert AEP’s Hogan – Mullin 34.5 kV line to 138 kV and establish a 138 kV connection between Jones Creek and Strawton stations. Also, rebuild existing Mullin – Elwood 34.5 kV line to increase capacity to address sub-transmission overloads. In the process of the rebuild, terminate the Mullin – Elwood 34.5 kV line into the Strawton station instead of the Mullin station and retire the Mullin station. (B2410)

  • Estimated Cost: $56M

  • Required IS Date: 6/1/2018
• **N-1 Violation**

  • The Hadley – Kroemer 69kV line is overloaded for various single contingencies
  
  • Rebuild the 3/0 ACSR portions of the Hadley – Kroemer Tap 69kV line utilizing 795 ACSR conductor. (B2411)
  
  • Estimated Cost: $3.0M
  
  • Required IS Date: 6/1/2014
**Voltage Violation**

- Low voltage and voltage drop violations at Sherwood, West Union, Varner, Mountwood and Lamberton 138kV buses for various single contingencies due to a local load increase

- Install a breaker and a half 138kV substation (WaldoRun) with four breakers to accommodate service to the new Facility including metering, which is cut into the Glen Falls – Lamberton 138kV line (B2433.1)
  - Estimated Cost: $30M
- Install a 70 Mvar SVC at the new WaldoRun 138KV Substation (B2433.2)
  - Estimated Cost: $20M
- Intall two 31.7 Mvar capacitors at the new WaldoRun 138kV Substation (B2433.3)
  - Estimated Cost: $2M
- Required IS Date: 12/31/2014
• **Project Scope Change**

• **B1237**

  • Original Scope: Upgrade terminal equipment at Albright 138 kV, replace bus and lineside breaker disconnects and leads, replace breaker risers, upgrade RTU and line trap
  • Previous Estimated Cost: $0.5M

  • New Scope: replace breaker leads and risers at Albright on Albright – Mettiki Tap 138kV line.
  • New Estimated Cost: $0.02M

• Required IS Date: 6/1/2015
• N-1-1 Voltage Violation

  • Low Voltage at Brackenridge, Eastgate, Edgewater, Hempfield, Luxor, Loyalhanna, North Greensburg, Stone Spring Junction, North Oakford, South Oakford, North Greensburg and Youngwood 138kV buses for the loss of the Sewickley – Yukon 138kV line and the loss of the Youngwood – Yukon 138kV line

  • Install a 44 MVAR 138 kV capacitor at the Hempfield 138KV substation. (B2412)

  • Estimated Cost: $1.1M

  • Required IS Date: 6/1/2018
• **N-1-1 Thermal Violation**

• The Shanango - McDowell 138kV line is overloaded for the loss of the Maple – Seneca 138kV line and the Butler – Shanor Manor 138kV line.

• Replace a relay at McDowell 138kV substation (B2413)

• Estimated Project Cost: $0.05M

• Required IS Date: 6/1/2018
• **N-1-1 Voltage Violation**

  Voltage drop violation at Barren County and Summer Shade 161kV buses for the loss of the Summer Shade EKPC-Summer Shade TVA 161 kV Line and the loss of the Summer Shade EKPC – Summer Shade Tap 161 kV Line.

• Build the 2nd Summer Shade EKPC - Summer Shade TVA 161 kV circuit (B2414)

• Estimated Project Cost: $4.6M

• Required IS Date: 6/1/2018
- **N-1-1 Thermal Violation**

- The Waukegan – Lake Hurst 138kV Blue line (L1606) is overloaded for the loss of Deerfield – Highland 138KV Blue line (L15912) and the loss of the Waukegan - Lake Hurst 138kV Red line (L1605)

- Install a 138 kV Red-Blue bus tie with underground cable and a line 15913 CB at Highland Park. (B2415)

- Estimated Project Cost: $8.0M

- Required IS Date: 6/1/2018
• **N-1-1 Thermal Violation**

• The East Frankfort – Mokena 138kV Red line is overload for the loss of the East Frankfort – Mokena Blue 138kV line (L6603) and the loss of the Bloom – Davis 345kV Blue line (L17907).

• Recondutor 0.125 miles of the 138 kV line 6604 from East Frankfort to Mokena. (B2416)

• Estimated Project Cost: $0.4M

• Required IS Date: 6/1/2018
• **N-1-1 Thermal Violation**

• The Ridgeland 138kV bus tie is overloaded for the loss of the Crawford 345/138/345 transformer #3 and the McCook – Ridge 138kV Red line (L5105)

• Replace Ridgeland 138 kV bus tie CB and underground cable at TSS 192 Ridgeland 138kV substation. (B2417)

• Estimated Project Cost: $6.0M

• Required IS Date: 6/1/2018
• **N-1-1 Thermal Violation**

  - The Waukegan – Gurnee 138kV Blue line is overloaded for the loss of the Wilson – Silver Lake Red 138KV line (L4202) and the loss of the Waukegan – Gurnee 138kV Red line (L1603)
  
  - Reconductor 7.5 miles of 138 kV line 1607 from Waukegan to Gurnee. (B2418)
  
  - Estimated Project Cost: $10M
  
  - Required IS Date: 6/1/2018
• **N-1-1 Thermal Violation**

  • The Sawyer – Crawford 138kV Blue line is overloaded for the loss of the Crawford – Goodings Grove 345kV Blue line (L1311) and the loss of the Crawford – Goodings Grove 345kV red line (L1311)

  • Reconductor 0.33 miles of 138 kV underground cable on the Sawyer – Crawford 138kV Blue line (L1324). (B2419)

  • Estimated Project Cost: $1.9M

  • Required IS Date: 6/1/2018
• The Turner 138 kV breaker ‘D’ is overstressed

• Proposed Solution: Replace the Turner 138 kV breaker ‘D’ (b2376)

• Estimated Project Cost: $800 K

• Required IS Date: 6/1/2014
The North Newark 138 kV breaker ‘P’ is overstressed

Proposed Solution: Replace the North Newark 138kV breaker ‘P’ (b2377)

Estimated Project Cost: $800 K

Required IS Date: 6/1/2014
• The East Lima 138 kV breaker ‘E’ is overstressed

• Proposed Solution: Replace the East Lima 138 kV breaker ‘E’ (b2381)

• Estimated Project Cost: $800 K

• Required IS Date: 6/1/2014
• The Delco 138 kV breaker ‘R’ is overstressed

• Proposed Solution: Replace the Delco 138 kV breaker ‘R’ (b2382)

• Estimated Project Cost: $800 K

• Required IS Date: 6/1/2014
• The Astor 138 kV breaker ‘102’ is overstressed

• Proposed Solution: Replace the Astor 138 kV breaker ‘102’ (b2386)

• Estimated Project Cost: $800 K

• Required IS Date: 6/1/2014
- The Sporn 345 kV breakers ‘DD,’ ‘DD2,’ ‘AA2,’ ‘CC,’ ‘CC2,’ and ‘CC1,’ are overstressed

- Proposed Solution: Replace the Sporn 345 kV breakers ‘DD,’ ‘DD2,’ ‘AA2,’ ‘CC,’ ‘CC2,’ and ‘CC1,’ (b2378, b2379, b2383-b2385, b2394)

- Estimated Project Cost: $1 M per breaker

- Required IS Date: 6/1/2014
The Muskingum River 345 kV breakers ‘SE,’ ‘SH,’ ‘S1,’ and ‘SG,’ are overstressed

Proposed Solution: Replace the Muskingum River 345 kV breakers ‘SE,’ ‘SH,’ ‘S1,’ and ‘SG,’ (b2380, b2387, b2388, b2390)

Estimated Project Cost: $1M per breaker

Required IS Date: 6/1/2014
• The Hyatt 138 kV breakers ‘105N,’ ‘101C,’ ‘104N,’ and ‘104S,’ are overstressed

• Proposed Solution: Replace the Hyatt 138 kV breakers ‘105N,’ ‘101C,’ ‘104N,’ and ‘104S,’ (b2389, b2391-b2393)

• Estimated Project Cost: $800 K per breaker

• Required IS Date: 6/1/2014
Dominion Transmission Zone

- **Dominion Criteria:**
  - Under critical system conditions (No Possum PT#5)
  - An outage of Line #590 (Loudoun to Brambleton 500 kV) overloads the Loudoun 500-230 kV Tx#1 & #2. (NERC Category B)
  - An outage of Line #590 (Loudoun to Brambleton 500 kV) and Line #551 (Mt Storm to Doubs 500 kV) overloads the Loudoun 500-230 kV Tx #1 & #2. (NERC Category C3 – “N-1-1”)

- **Solutions Considered**
  - Build second Loudoun – Brambleton 500 kV on existing ROW - $13 M
  - Install a third 500/230 kV transformer at Loudoun - $20 M
  - Replace both transformers with larger units - $30 M

- **Proposed Solution:** Build a second Loudoun – Brambleton 500 kV Line within the existing ROW. Line #2094 (Loudoun to Brambleton 230 kV) will be relocated as an underbuild on the new 500 kV Line. (b2373)

- Estimated Project Cost $13 M
- Expected In-service Date: 06/01/2018
• The East Springfield 138 kV breaker ‘211-B-63’ is overstressed

• Proposed Solution: Replace the East Springfield 138 kV breaker ‘211-B-63’ with 40kA breaker (b2349)

• Estimated Project Cost: $250 K

• Expected IS Date: 6/1/2018
• The East Akron 138 kV breaker '36-B-46' is overstressed

• Proposed Solution: Replace the East Akron 138 kV breaker '36-B-46' with 40kA breaker (b2367)

• Estimated Project Cost: $250 K

• Expected IS Date: 6/1/2018
The Brambleton 230 kV breakers ‘20902,’ ‘213702,’ and ‘H302’ are overstressed.

Proposed Solution: Brambleton 230 kV breakers ‘209502,’ ‘213702,’ and ‘H302’ with 63kA breaker (b2368-2370)

Estimated Project Cost: $215 K

Expected IS Date: 6/1/2016
• The Erie South 115 kV breaker ‘French #2’ is overstressed

• Proposed Solution: Replace the Erie South 115 kV breaker ‘French #2’ with 40kA breaker (b2302)

• Estimated Project Cost: $179 K

• Expected IS Date: 6/1/2014
• The East Windsor 230 kV breaker ‘E1’ is overstressed

• Proposed Solution: Replace the East Windsor 230 kV breaker ‘E1’ with 63kA breaker (b2357)

• Estimated Project Cost: $850 K

• Expected IS Date: 6/1/2016
- Recommend Northern PSE&G Short Circuit solution alternative

- Continue Artificial Island evaluation including thermal and voltage analysis of alternatives

- Finalize 2013 RTEP criteria violations
2013 RTEP Scenario Analysis Update
2013 RTEP - At Risk Generation Scenarios
• At-risk generation categories
  – Environmental
    • Environmental controls retrofit status
    • Retrofit schedule (or lack of)
  – RPM
    • Cleared / Not cleared
  – Other announcements
• At-Risk MW in addition to known Deactivation Notifications*
  – I.e. 4,918 of deactivation notifications in 2013 not included in the number below

• Approximately 6,000 MW

* As of November 2013
At-Risk Generation

- **Purpose**
  - Identify potential regional and local reliability concerns

- **Overall Assumptions**
  - 2018 RTEP Base Case
  - 2013 PJM Load Forecast Report
    - Include Demand Response (DR) and Energy Efficiency (EE)
Performed the following analysis
  – Basecase contingency analysis
    • Single
    • Multiple
  – N-1-1 500 kV and above contingencies

Identified overloads are local facilities and no regional solution is anticipated to be needed.

The actual violations will depend on which generators ultimately notify PJM of retirement.
Consideration of facility conductor limits

Results
- Mostly < 230 kV overloads
- Very few 230 kV overloads
- No > 230 kV overloads
2013 RTEP – Renewable Portfolio Standards Scenarios
Background and Status
• **Assumptions**
  – Installed/Imported wind to meet PJM’s RPS requirements
  – Study year: 2028

• **Analysis**
  – Reliability Analysis (50/50 load level)
    • Generator Deliverability
      – Single Contingencies
      – Common Mode Outage test (DCTLs)
    • Security Constrained Optimal Power Flow (Light Load – 50% of Peak Load) (SCOPF)
  – Market Efficiency Analysis
    • Production cost simulation using PROMOD
Results

- Reliability Analysis
  - Thermal overloads (using PJM’s criteria)
  - Develop reliability overlay
- Market Efficiency
  - Monitor: Market Flowgates & Reliability Analysis Flowgates (85% loading)
  - Future congestion $’s and load payments for year 2028
  - Generation curtailments
  - Adjust transmission overlay to fix high congestion elements
• Overlay Development Method
  – Terminal equipment upgrades
  – Re-conductor existing transmission lines
  – Build parallel circuits/transformers
  – Build new transmission lines/paths
    • Collection for offshore injection
• Scenario 1, 1A, 1B, 2, & 3
  – Reliability Analysis Completed
    • Reliability Overlay Developed
  – Market Efficiency Simulation Completed
    • Simulation with and without reliability overlay finished
    • Adjustment to transmission overlay for high congestion completed

• Next Steps
  – Analysis specific to NJ Resolution
Results Summary
Observations (S1, S1A, S1B, S2 & S3)

• Overall fewer constraints v. 2012 RTEP analysis
  – On shore - retirements, addition of queue generation/upgrades drive fewer limits
  – Off shore - injections cause higher levels of limits
  – Upgrades are scenario specific, lower drivers for large backbone

• Scenario 1 AC upgrades ($4.5-6 billion) similar to 2012 RTEP analysis

• Scenarios 2 and 3 AC upgrades ($1 – 3.5 billion) significantly lower than 2012 RTEP
Observations (S1, S1A, S1B, S2 & S3)

- Transmission upgrades are conceptual and based on judgments consistently applied across scenarios.
- Reliability first analysis addresses most limits
- Curtailments before upgrades low except Virginia. Upgrades remedy curtailment
- Upgrades decrease load payments by ≈$450 – 850 million (≈.5% - 1.5% reduction on ≈$70 billion)
- Upgrades decrease congestion by ≈$1.1 – 1.7 billion (≈60% - 85% reduction on ≈$2 billion)
### Upgrade drivers (S1A, S1B, S1)

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>Light Load</th>
<th>Peak</th>
<th>Congestion</th>
<th>Grand Total</th>
</tr>
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<td>45</td>
<td>4</td>
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<td>1</td>
<td>2</td>
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</tr>
<tr>
<td>138</td>
<td>1</td>
<td>1</td>
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<tr>
<td>Grand Total</td>
<td>10</td>
<td>56</td>
<td>10</td>
<td>76</td>
</tr>
</tbody>
</table>

### S1A Reliability Analysis Overloads

- **Analysis**
- **Voltage Level**
- **Light Load**
- **Peak**
- **Congestion**
- **Grand Total**

### S1B Reliability Analysis Overloads

- **Analysis**
- **Voltage Level**
- **Light Load**
- **Peak**
- **Congestion**
- **Grand Total**

### AC $1.3-2.7$ billion / DC $2.8$ billion

*(Transmission)*

### S1 Reliability Analysis Overloads

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>Light Load</th>
<th>Peak</th>
<th>Congestion</th>
<th>Grand Total</th>
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<tr>
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<tr>
<td>138</td>
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<tr>
<td>Grand Total</td>
<td>16</td>
<td>68</td>
<td>9</td>
<td>93</td>
</tr>
</tbody>
</table>

### AC $4.3-5.6$ billion / DC $3.8$ billion

*(transmission)*

### AC $4.6-6.1$ billion / DC $8.9$ billion

*(transmission)*
### Upgrade drivers (S2, S3)

**S2 Reliability Analysis Overloads**

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>Light Load</th>
<th>Peak</th>
<th>Congestion</th>
<th>Grand Total</th>
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<td>6</td>
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<tr>
<td>345</td>
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<td>10</td>
<td>4</td>
<td>15</td>
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<td>500</td>
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<td>1</td>
<td>2</td>
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</tr>
<tr>
<td>765</td>
<td>1</td>
<td>1</td>
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<td></td>
</tr>
<tr>
<td>138</td>
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<td>1</td>
<td>1</td>
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<tr>
<td><strong>Grand Total</strong></td>
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<td><strong>51</strong></td>
<td><strong>11</strong></td>
<td><strong>65</strong></td>
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</table>

**S3 Reliability Analysis Overloads**

<table>
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<th>Voltage Level</th>
<th>Light Load</th>
<th>Peak</th>
<th>Congestion</th>
<th>Grand Total</th>
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<tbody>
<tr>
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<td>41</td>
<td>6</td>
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<td>345</td>
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<td>14</td>
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<td>20</td>
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<td>500</td>
<td>1</td>
<td>1</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>765</td>
<td>1</td>
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<td>1</td>
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<tr>
<td>138</td>
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<tr>
<td><strong>Grand Total</strong></td>
<td><strong>4</strong></td>
<td><strong>57</strong></td>
<td><strong>12</strong></td>
<td><strong>73</strong></td>
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</tbody>
</table>

**Analysis**

**S2 Reliability Analysis Overloads**

**Voltage Level**

- 230
- 345
- 500
- 765
- 138

**Light Load**

- 1

**Peak**

- 39
- 10
- 1
- 1
- 1

**Congestion**

- 6
- 4
- 1
- 1
- 1

**Grand Total**

- 46
- 15
- 2
- 1
- 1

**S3 Reliability Analysis Overloads**

**Voltage Level**

- 230
- 345
- 500
- 765
- 138

**Light Load**

- 1
- 2
- 1
- 1
- 2

**Peak**

- 41
- 14
- 1
- 1
- 2

**Congestion**

- 6
- 4
- 1
- 1
- 2

**Grand Total**

- 48
- 20
- 2
- 1
- 2

**AC $1.3-2.6 billion**

(Transmission)

**AC $1.6-3.4 billion**

(transmission)
Observations (S1, S1A, S1B, S2 & S3)

- DC Loop (S1, S1A, S1B)
  - Functions to optimize production
  - Generally lowers remaining curtailments
  - Lowers congestion
  - DC load payment benefit of $65 - $40 million in S1A and S1B
  - With Virginia off shore injection (S1) DC loop causes increases and decreases in PJM load costs (net increase)
Observations (S1, S1A, S1B, S2 & S3)

- With Upgrades
  - Curtailments not an issue (highest is 0.2% in S2)
  - Congestion is highest in S2 and S3
  - Load payments close in all scenarios with or without upgrades (within 3%)
  - S1, S2 and S3 all meet RPS requirements
  - S1A and S1B are steps to S1 RPS compliance
  - S2 is lowest overall cost
  - S3 will have added transmission cost for imports
### Renewable Portfolio Standards (RPS)

#### 2028 RPS Study Generation (MW)

<table>
<thead>
<tr>
<th>Description</th>
<th>Solar</th>
<th>Wind</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target Installed Nameplate for Renewables based on State Targets*</td>
<td>5,600</td>
<td>32,300</td>
<td>37,900</td>
</tr>
<tr>
<td>Existing Installed Nameplate</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Solar</td>
<td>249</td>
<td></td>
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<tr>
<td>Wind</td>
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<td>6,851</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>6,851</td>
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<tr>
<td>Forecast Restricted Demand ** (2013 PJM Load Forecast)</td>
<td></td>
<td>173,753</td>
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</tr>
<tr>
<td>Installed Reserve Margin</td>
<td></td>
<td>20%</td>
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</tr>
<tr>
<td>Installed Capacity Needed</td>
<td></td>
<td>208,504</td>
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<tr>
<td>Installed Capacity Credit for new Renewables based on State Targets***</td>
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<tr>
<td>Solar</td>
<td>2,030</td>
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<tr>
<td>Wind</td>
<td>3,850</td>
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<tr>
<td>Total</td>
<td></td>
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<td>5,880</td>
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<tr>
<td>Current Installed Capacity in 2018 Base Case</td>
<td>183,541</td>
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<tr>
<td>External ICAP</td>
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<tr>
<td>Pending Deactivations</td>
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<tr>
<td>Active Non-Renewable Capacity Needed S1 &amp; S2</td>
<td>17,733</td>
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<td>Additional Non-Renewable Capacity Needed S3</td>
<td>7,405</td>
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<tr>
<td>Additional Non-Renewable Capacity Needed S3</td>
<td>6,928</td>
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</table>

* Capacity factors based on historical data
** Assumes ~12,000 MW of DR
*** Assumes 38% for solar and 15% for wind
### Renewable RPS Requirements and Assumptions

#### Total GW

<table>
<thead>
<tr>
<th>Target Renewable Nameplate*</th>
<th>Solar</th>
<th>Total</th>
<th>Renewable Queue Projects in RTEP</th>
<th>Solar</th>
<th>S1 GW</th>
<th>S2 GW</th>
<th>S3 GW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing Installed Nameplate</td>
<td>Wind</td>
<td>32.3</td>
<td>Wind on shore in PJM</td>
<td>14.7</td>
<td>2.2</td>
<td>2.2</td>
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<tr>
<td></td>
<td>Total</td>
<td>37.9</td>
<td>Wind on shore imports</td>
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<td>0</td>
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<tr>
<td>New Renewables Needed</td>
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<td>Wind off shore</td>
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<td>Total</td>
<td>31.1</td>
<td>Total</td>
<td>17.9</td>
<td>17.9</td>
<td>17.9</td>
<td>17.9</td>
</tr>
</tbody>
</table>

### Target Renewable Nameplate*

- **Solar**: 5.6
- **Wind**: 32.3
- **Total**: 37.9

### Renewable Queue Projects in RTEP

- **Solar**: 0.3
- **Wind**: 6.6
- **Total**: 6.9

### Conceptual Renewable Projects added

- **Solar**: 5.4
- **Wind**: 25.7
- **Total**: 31.1
State Renewable Requirements v. Production – S3

- % of Load served by Wind
- % of Load served by Wind and Solar
- RPS Requirements by States
Results
• Scenario 1 (7GW Offshore)
  – Hudson approx. 1.5GW offshore injection
  – Cardiff approx. 1.5GW offshore injection
  – Indian River approx. 1.5GW offshore injection
  – Sewells Point approx. 1.5GW offshore injection
  – Existing offshore ISA/FSAs: approx. 1GW
  – 2x 1,000MW HVDC lines between each offshore injection point
Reliability Analysis Overloads - Scenario 1

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>Light Load</th>
<th>Peak</th>
<th>Grand Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>230</td>
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<td>10</td>
<td>18</td>
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<tr>
<td>500</td>
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<tr>
<td>Grand Total</td>
<td>16</td>
<td>68</td>
<td>84</td>
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</tbody>
</table>
• Scenario Sensitivity RPS1A:
  – Hudson 1GW offshore injection
  – Cardiff 1GW offshore injection
  – DC line between Hudson and Cardiff
  – 1x 1,000MW HVDC lines between each offshore injection point

• Scenario Sensitivity RPS1B:
  – Hudson 1GW offshore injection
  – Cardiff 1GW offshore injection
  – Cedar 1GW offshore injection
  – DC line between Hudson and Cedar and Cardiff
  – 1x 1,000MW HVDC lines between each offshore injection point
Reliability Analysis Overloads - Scenario 1A

Legend
- Subs := 590 kV
- Trans Lines := 500 kV
- Subs := 345 kV
- Trans Lines := 345 kV
- SCOPF Constraints Scenario 1A
- Generator Deliverability Constraints Scenario 1A

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>Analysis</th>
<th>Light Load</th>
<th>Peak</th>
<th>Grand Total</th>
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<tbody>
<tr>
<td>230</td>
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<td>1</td>
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<tr>
<td>345</td>
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<td>10</td>
<td>18</td>
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<tr>
<td>500</td>
<td></td>
<td>1</td>
<td></td>
<td>1</td>
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<tr>
<td>Grand Total</td>
<td></td>
<td>9</td>
<td>56</td>
<td>65</td>
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</tbody>
</table>
• Scenario 2
  – PJM internal onshore resources
  – Approx. 10GW of new onshore wind installed
  – Approx. 3.2GW of new solar PV installed
• **Scenario 3**
  – Additional RPS requirements met with imports (~31%)
  – Approx.: 2.4GW injections
  – 4 Injection points
    • Marysville 765kV
    • Jacksons Ferry 765kV
    • Collins 765kV
    • Sullivan 765kV
Reliability Analysis Overloads - Scenario 3

Legend
- Subs <= 500 kV
- Trans Lines >= 500 kV
- Subs = 345 kV
- Trans Lines = 345 kV
- Generator Deliverability Constraints Scenario 3
- SCORF Constraints Scenario 3

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>Analysis Light Load</th>
<th>Analysis Peak</th>
<th>Grand Total</th>
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<tr>
<td>230</td>
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<tr>
<td>345</td>
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<tr>
<td>500</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>765</td>
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<td>1</td>
<td>1</td>
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<tr>
<td>Grand Total</td>
<td>4</td>
<td>57</td>
<td>61</td>
</tr>
</tbody>
</table>
HVDC Flows – Scenario 1

No Overlay

- Hudson: 2,106MW → 566MW
- Cardiff: 1,419MW → 566MW
- Indian River: 1,027MW → 550MW
- Sewels Point: 507MW → 539MW

with Overlay

- Hudson: 886MW → 566MW
- Cardiff: 83MW → 566MW
- Indian River: 614MW → 550MW
- Sewels Point: 804MW → 539MW

HVDC Limit Enforced

2,000MW
HVDC Flows – Scenario 1A

No Overlay

Hudson 1,155MW 384MW
Cardiff 387MW 384MW

with Overlay

Hudson 857MW 384MW
Cardiff 89MW 384MW

1,000MW HVDC Limit Enforced
<table>
<thead>
<tr>
<th>Location</th>
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<th>with Overlay</th>
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<tr>
<td>Hudson</td>
<td>1,119MW</td>
<td>423MW</td>
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<tr>
<td></td>
<td>384MW</td>
<td>384MW</td>
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<tr>
<td>Cedar</td>
<td>646MW</td>
<td>804MW</td>
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<tr>
<td></td>
<td>384MW</td>
<td>384MW</td>
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<tr>
<td>Cardiff</td>
<td>613MW</td>
<td>75MW</td>
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<td></td>
<td>384MW</td>
<td>384MW</td>
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</table>

**HVDC Flows – Scenario 1B**

1,000MW HVDC Limit Enforced
RPS Market Efficiency Overview
Overlay Drivers
Wind Curtailment – Scenarios 1, 1A, & 1B

- RPS-1 - No DC - with Overlay
- RPS-1 - No DC - No Overlay
- RPS-1A - No DC - with Overlay
- RPS-1A - No DC - No Overlay
- RPS-1B - No DC - with Overlay
- RPS-1B - No DC - No Overlay
Congestion Overlay Affect – PJM-Wide

![Bar Chart]

- RPS-1
- RPS-1A
- RPS-1B
- RPS-2
- RPS-3
Congestion – Scenarios 2 & 3

The diagram illustrates the financial impact of different scenarios on the PJM market. The y-axis represents the financial impact in dollars, ranging from $0 to $1,600,000,000. The x-axis categorizes the regions as EMAAC, Rest of MAAC, and Rest of PJM. The scenarios are differentiated by color:
- RPS2 - with Overlay
- RPS2 - No Overlay
- RPS3 - with Overlay
- RPS3 - No Overlay

The data shows a significant increase in financial impact for the Rest of PJM under certain scenarios, highlighting the potential economic consequences of different market conditions.
Load Payments Overlay Affect – PJM-Wide

Negative Overlay
Reduced Load Payment

Positive Overlay
Increased Load Payment
Load Payments Overlay Affect – by State

- Negative Overlay Reduced Load Payment
- Positive Overlay Increased Load Payment

Graph showing load payments by state for different overlays (RPS-1, RPS-1A, RPS1-B, RPS-2, RPS-3).
Offshore HVDC Comparison
Wind Curtailment (with upgrades) – Scenarios 1, 1A, & 1B
Negative HVDC Reduced Load Payment

Positive HVDC Increased Load Payment
Load Payments HVDC Affect – by State

Negative HVDC Reduced Load Payment

Positive HVDC Increased Load Payment
Load Payments HVDC Affect – by State

Negative HVDC Reduced Load Payment

Positive HVDC Increased Load Payment
Scenario Comparison
Wind Curtailment (with upgrades)

- RPS-1
- RPS-1A
- RPS-1B
- RPS-2
- RPS-3

Chart showing the percentages of wind curtailment for different regions.
Load Payments (with upgrades)
Cost Estimation
### AC On-Shore Overlay Cost Estimate Assumptions (2013 Nominal $M/mi)

<table>
<thead>
<tr>
<th>PJM Area</th>
<th>New</th>
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<td>AE-500kV</td>
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<td>AEP-345kV</td>
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<td>AP-138kV</td>
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<td>COMED-138kV</td>
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<td>DEOK-345kV</td>
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<td>DLCO-138kV</td>
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<td>DOM-230kV</td>
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<td>DOM-500kV</td>
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<td>DPL-230kV</td>
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<td>FE-345kV</td>
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<td>JCPL-230kV</td>
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<td>PECHO-230kV</td>
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<td>PENELAP-230kV</td>
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<td>PEPCO-230kV</td>
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### Cost Estimating Assumptions (2013 Nominal $)

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<th>Equipment Type</th>
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<td>Xfmr</td>
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<td>345/138kV</td>
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<td>765/345kV</td>
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<table>
<thead>
<tr>
<th>DC Cable</th>
<th>$/mi</th>
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<tr>
<td>Backbone Offshore</td>
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<tr>
<td>Radial Offshore</td>
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<tr>
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<tr>
<th>Upgrade Terminal Equip.</th>
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<table>
<thead>
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<th>Wind Capital Cost</th>
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# RPS Wind and AC Overlay Cost Estimates (2028 Nominal $B)

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<tr>
<th>Year 2028 ($B)</th>
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<th>S1A</th>
<th>S1B</th>
<th>S2</th>
<th>S3</th>
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<td>Onshore Converters</td>
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<td>0.4</td>
<td>0.6</td>
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<td>Offshore Platform Converters</td>
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<tr>
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<tr>
<td>Offshore DC Radial</td>
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<td>Onshore DC Radial</td>
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<td>0.2</td>
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<tr>
<td><strong>Total DC Loop</strong></td>
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<td>2.8</td>
<td>3.8</td>
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<td>Offshore Turbine Capital</td>
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<td>PJM Onshore Turbine Capital</td>
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<td>51.5</td>
<td>51.5</td>
<td>68.0</td>
<td>40.5</td>
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<td>Imported Onshore Turbine Capital</td>
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<td>27.5</td>
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<td>DC Wind Import Trans. Capital</td>
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<td><strong>Total Wind Capital Cost</strong></td>
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<td><strong>Total Scenario Cost</strong></td>
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<td>67.9</td>
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</tbody>
</table>
Questions?

Email: RTEP@pjm.com
• 11/6/2013 v1 – Original version distributed to PJM TEAC
• 11/7/2013 v2
  – Modified Slide # 6 – Updated the existing cost of the Monocacy reactor from $0.3M (typographical error) to $4M
  – Deleted Slide # 11 – The cancellation of B1980: New Beaver Valley - Leroy Center 345kV + Mansfield - Leroy Center 345kV lines isn’t required since this project was never included in the RTEP, only considered for inclusion.
  – Added Slide #104 - Added to the previously presented upgrades section. Add a 2nd Loudoun – Brambleton 500 kV circuit
  – Added Slides #105-109 - Added several short circuit breaker upgrades to the previously presented upgrades section.
• 11/8/2013 v3
  – Update to “Upgrade drivers (S1A, S1B, S1)” in the RPS section, Slide # 127
  – Update to “RPS Wind and AC Overlay Cost Estimates (2028 Nominal $B)” in the RPS section, Slide # 178