Transmission Expansion Advisory Committee

April 10, 2014

Interregional Planning Update

EIPC non-grant 2014 Analysis

- Stakeholder WebEx March 25
- Stakeholder proposed scenarios
  - Winter stressed case (EIPC sample)
  - Spring stressed case (EIPC sample)
  - Severe drought (EISPC)
  - Update rollup case (NYISO PSC)
  - Indian Point and increased gas generation (NYISO PSC)
  - Increased gas generation (NYISO PSC)
  - High transmission build-out (NYISO PSC)
  - Nuclear shutdown (EISPC)

EIPC Future Direction Discussion

- NERC power flow compliance responsibility
- DOE congestion study data collection
- 2015/16 Work Plan possibilities
  - 10 year map
  - Rollup (add winter case), engage NERC process
  - Scenarios
  - Production Cost

Interregional Planning Studies (not including JCM)

- NCTPC
  - Study requested by NCUC
  - Reliability and Economic impact of BRA resources
  - Scope under development
  - 2014 target completion
- PJM/MISO Joint Planning Study
  - Futures 1, 2, 3
  - No Future 1 projects pass yet
  - Futures 2 and 3 still being checked
  - Stakeholder comments still being evaluated

Reliability Analysis Update

Winter Peak Study Update

2019 Winter Study Update

- Winter Study case
  - Same topology as 2019 Summer Peak case
  - External model using MMWG winter model
  - Winter Rating and Winter load profile submitted from TO
  - PJM Winter load forecast
  - Generation dispatch based on capacity factor during winter peak hours
  - Area interchange (Firm transfer Vs Historical metered data will be compared)
- Study Methodology
  - Deliverability test similar to light load test with different ramping level
  - CETO test (gas line contingency will be included)

2018 CETO/CETL Values

Brattle Recommendation

- Brattle recommendation for an annual “CETL forecast”

- 2013 RTEP Assumptions
  - Include transmission approved by the PJM Board through December 2013

- 2018 CETO/CETL values based on 2013 RTEP assumptions

- Limiting facilities identified

Year 2018 RTEP Base Case CETO/CETL Values

2018 RTEP Base Case CETO & CETL Values					
Area	MW CETO	MW CETL	CETL/CETO %	Limiting Facility	Violation Type
AE	1130	2322	205.5%	Voltage violation for the loss of Orchard - Cumberland 230 kV circuit	Voltage
AEP	1260	>4222	335.1%		
APS	3740	>7652	204.6%		
ATSI	4970	8470	170.4%	South Canton - Harmon 345 kV circuit	Thermal
BGE	4350	6217	142.9%	Pumphrey 230/115 kV	Thermal
CLEVELAND	3350	4940	147.5%	South Canton - Harmon 345 kV circuit	Thermal
COMED	2290	7020	306.6%	University Park – East Frankfort 345kV circuit	Thermal
DAYTON	970	>1455	150.0%		
DLCO	1520	>2280	150.0%		
DPL	980	>1470	150.0%		
DPL SOUTH	1440	1869	129.8%	Easton - Trappe Tap 69 kV circuit	Thermal
DEOK	3760	5065	134.7%	Pierce - Beckjord 138 kV circuit '1887'	Thermal
EKPC	250	>574	229.6%		
EMAAC	6140	9315	151.7%	Voltage collapse for the loss of the Keeney - Rock Springs 500 kV circuit	Voltage
JCPL	3370	>5055	150.0%		
MAAC	4420	7393	167.3%	Bristers - Ox 500 kV circuit	Thermal
METED	1290	2954	229.0%	Yorkana 230/115 kV transformer	Thermal
PECO	3260	>6172	189.3%		
PENELEC	600	>1083	180.5%		
PEPCO	3740	5359	143.3%	Voltage collapse for the loss of Burches Hill - Possum Point 500 kV circuit	Voltage
PJM WEST	8210	>12135	147.8%		
PLGRP	1310	4336	331.0%	Wescosville 500/138 kV transformer	Thermal
PSEG	6080	6700	110.2%	Roseland - Wilpipe 230 kV 230 kV circuit	Thermal
PSEG NORTH	2370	2795	117.9%	Roseland - Wilpipe 230 kV 230 kV circuit	Thermal
SWMAAC	5880	8053	137.0%	Voltage collapse for the loss of Burches Hill - Possum Point 500 kV circuit	Voltage
VAP	-540	>2089	386.9%		
WMAAC	-5010	>-1638	32.7%		

2020 Summer Peak Study Results

2020 Summer Peak Study Result

- 2020 (Year 8) summer peak case studied as part of the 2012 RTEP
- 2020 (Year 7) summer peak case studied as part of the 2013 RTEP
- Based on this study, no longer lead time system reinforcements recommended at this time
- 2022 (Year 8) summer peak base case will be created as part of the 2014 RTEP

2020 Summer Thermal Analysis

Single Contingency Result							
Fr Bus	**Fr Name**	**To Bus**	**To Name**	**CKT**	**KVs**	**Areas**	**100% Year**
219110	GLOUCSTR_2	219753	CUTHBERT_2	1	230/230	PSEG	2020
219108	CUTHBERT	219125	CAMDEN	2	230/230	PSEG	2021
314074	6POSSUM	314096	6WOODB A	1	230/230	DOMINION	2028
214206	RICHMRE29	213922	RICHMOND	1	230/230	PECO	2026
314074	6POSSUM	314029	6DUMFRES	1	230/230	DOMINION	2024
232004	MILF_230	232001	COOLSPGS	1	230/230	DPL	2025
219754	CUTHBERT_3	219125	CAMDEN	1	230/230	PSEG	2020
219110	GLOUCSTR_2	219755	CUTHBERT_4	2	230/230	PSEG	2020
213519	CONOWG01	231006	COLOR_PE	1	230/230	PECO/DPL	2027
231004	RL_230	232002	CEDAR CK	1	230/230	DPL	2020
213520	CONOWG03	213844	NOTTNGHM	1	230/230	PECO	2026

Tower Contingency Result							
Fr Bus	**Fr Name**	**To Bus**	**To Name**	**CKT**	**KVs**	**Areas**	**100% Year**
217079	ESSEX	217061	KRNY_4-6	1	230/230	PSEG	2029
314094	6WOODBR	314067	6OCCOQUN	1	230/230	DOMINION	2026
314074	6POSSUM	314029	6DUMFRES	1	230/230	DOMINION	2024
314171	6BRAMBL	314006	6ASHBURA	1	230/230	DOMINION	2023
208040	MONT	208034	MILT	1	230/230	PPL	2025
905190	W4-021 TAP	206292	28FRENEAU	1	230/230	JCPL	2028
206314	28RED OAKA	206305	28RAR RVR	1	230/230	JCPL	2026

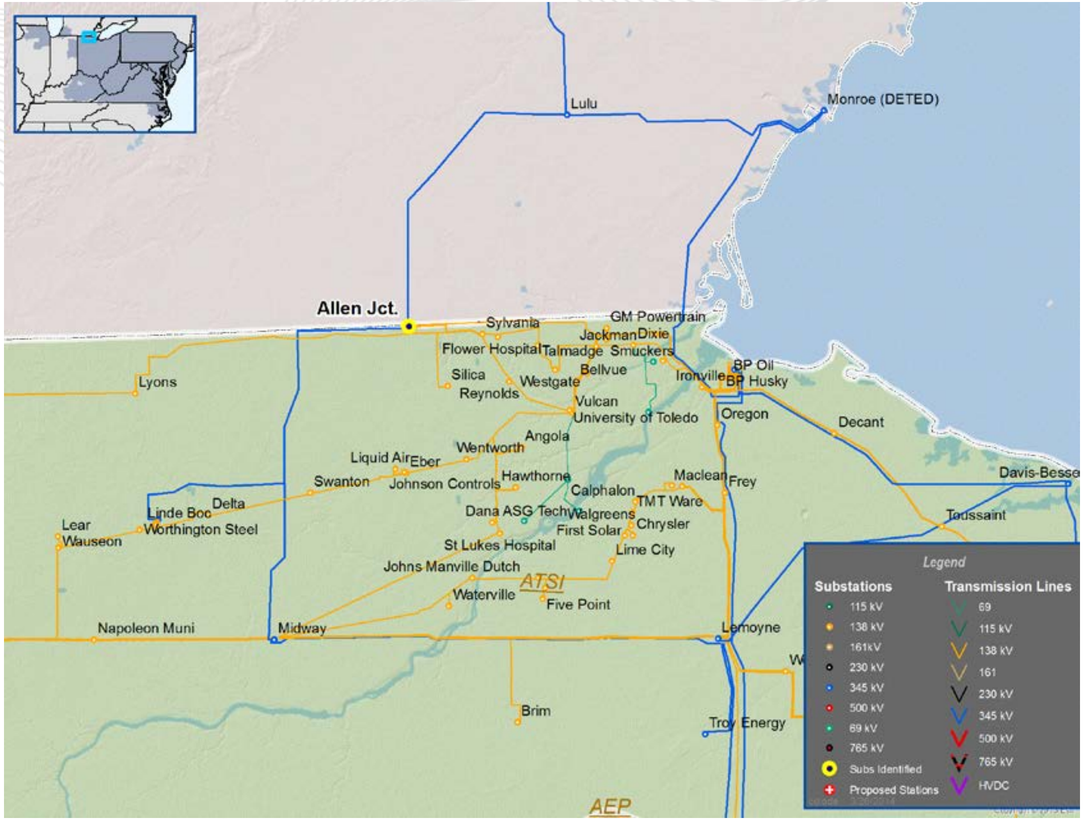
Supplemental Projects

ATSI Transmission Zone

- Supplemental Project

- Associated work in the PJM ATSI transmission zone for MISO MTEP13 project
  - 4292: Allen Junction (FE) – Lenawee (ITC) 345kV Tie Line – MTEP13
  - ITC will be creating a new 345/138kV substation named Lenawee
  - The existing Beecher - Whiting 138kV, Beecher-Samaria 138kV, and the Allen Junction – Milan - Monroe 345kV lines will loop into the new substation.
  - The Milan/Monroe 345kV line exit at Allen Junction will be converted to the Lenawee 345kV line exit.

- PJM Supplemental: Upgrade the equipment on the existing Milan/Monroe 345kV line in order to become compatible with the new relaying & equipment at Lenawee (S0693)
- Projected IS Date: 4/1/2015

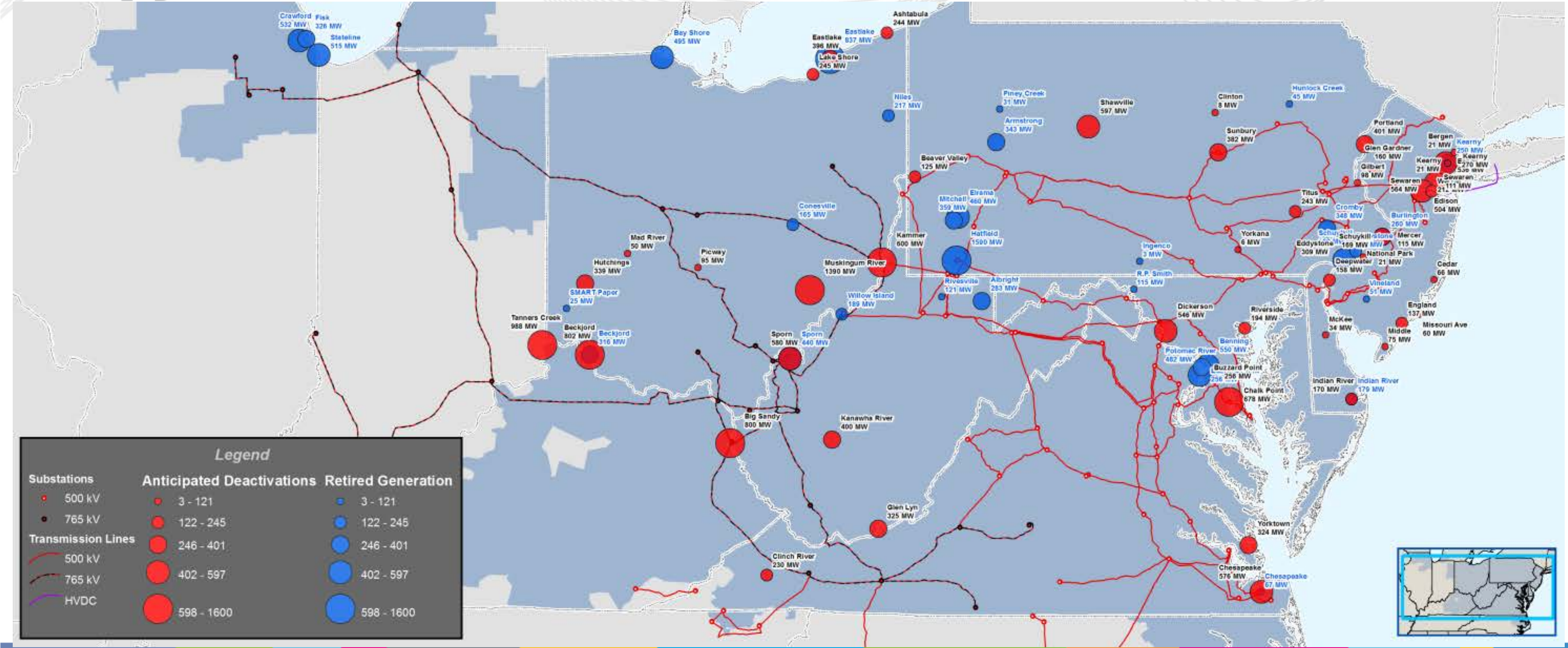


Generation Deactivation Notification Update

Deactivation Status

Unit(s)	Transmission Zone	Requested Deactivation Date	PJM Reliability Status
McKee Units 1 & 2 (17MWs each)	DPL	5/31/2017	Reliability analysis complete. No impacts identified.
Dale Units 1-4 (193MWs total)	EKPC	4/16/2015	Reliability analysis underway

Generation Retirements

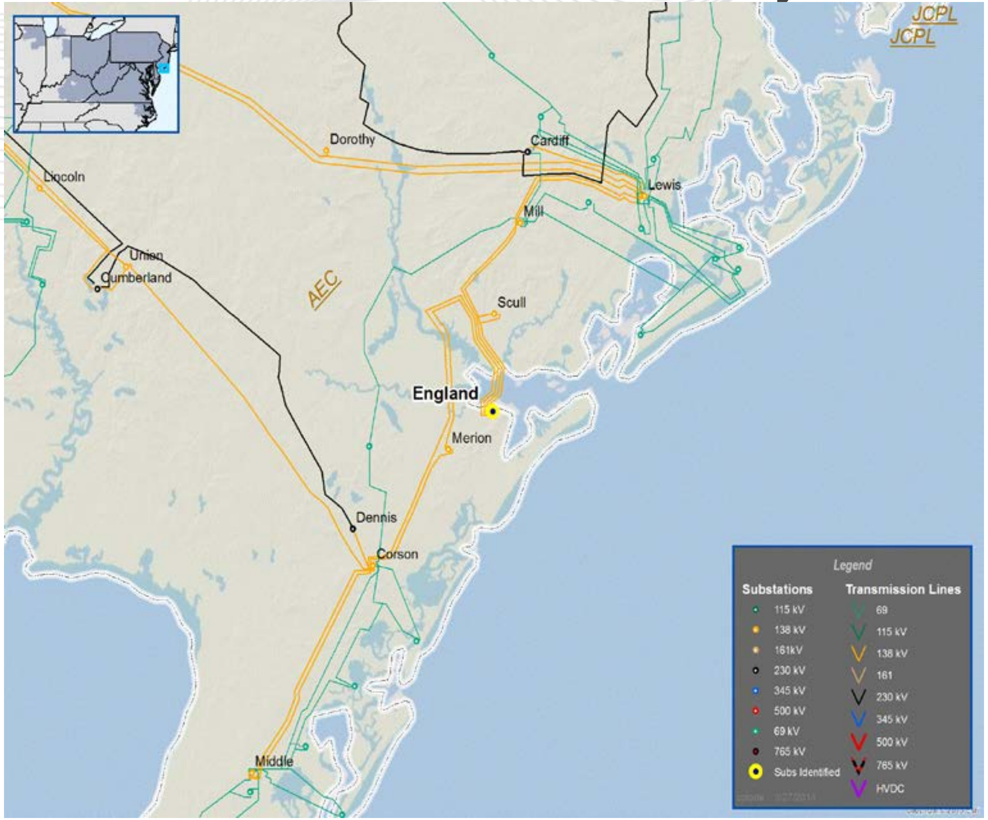


At Risk Generation Analysis

Generator At Risk Analysis

- BL England unit 2: 155MW
- BL England unit 3: 148.9MW
  - ACE Transmission Zone
  - 288 MW Total
  - Study Year: 2015

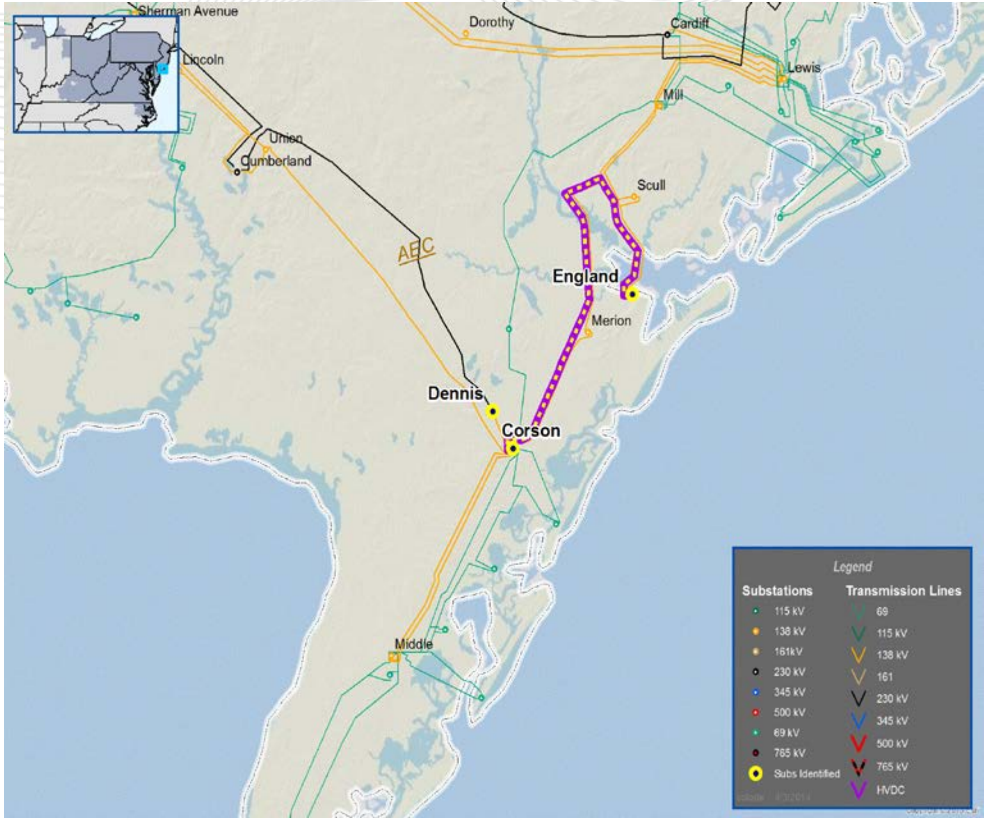
- BL England unit 1 & diesels were modeled offline in this study as it was already studied for deactivation



ACE Transmission Zone

At Risk – BL England Units 2 & 3

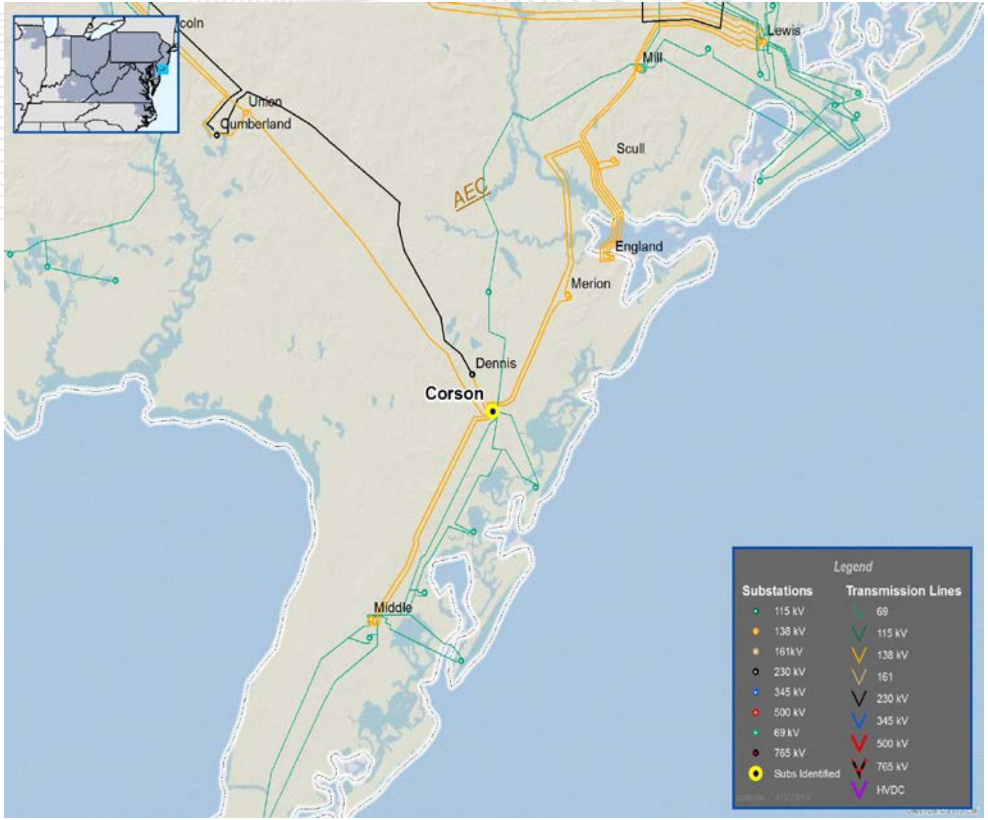
- N-1-1 Violation
- The DENNIS 230/138kV transformer is overloaded to 119.35% and DENNIS – CORSON 2 138kV line is overloaded to 114.37% for the loss of the New Freedom to Cardiff 230 kV line (CONTINGENCY 'NEWFDM-CARD') followed by the loss of Corson 3 – Union 138kV line (CONTINGENCY 'CORSON-UNION')
- *The MDLE TP – BLE 138kV line is overloaded to 102.81% for the loss of New Freedom – Cardiff 230 kV line followed by the loss of Oyster Creek – Cedar 230 kV line*
- Install new Dennis 230/69kV transformer
- Cost Estimate: $15.2M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/01/2016



At Risk – BL England Units 2 & 3

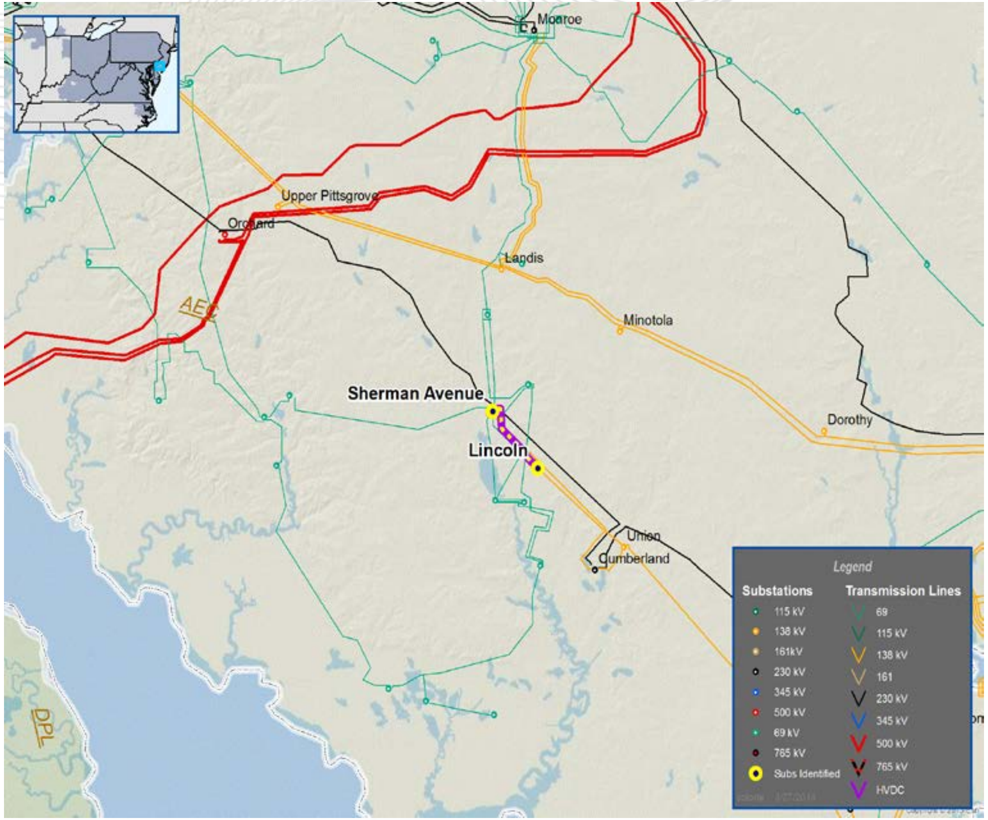
ACE Transmission Zone

- N-1-1 Violation
- The CORSON 2 - CORSON 1 138kV line is overloaded to 115.97% for the loss of the New Freedom to Cardiff 230 kV line (*CONTINGENCY 'NEWFDM-CARD'*) followed by the loss of Corson 2 – MDLE TP kV 138kV line (*'228107(CORSON 2)-228111(MDLE TP)_1'*)
- The CORSON 2 - MDLE TP 138kV line is overloaded to 114.31% *for the loss of New Freedom – Cardiff 230 kV line followed by the loss of Corson 1 – Corson 2 138kV line* (*CONTINGENCY '228106(CORSON 1)-228107(CORSON 2)_1'*)
- Upgrade 138kV and 69kV breakers at Corson substation
- Cost Estimate: $0.8M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/01/2016



ACE Transmission Zone

- N-1-1 Violation
- The SHRMAN#3 - LINCOLN 138kV line is overloaded to 103.22% for the loss of the Dennis – Corson 2 138kV (*CONTINGENCY 'DENN-COR'*) followed by the loss of Union – Cumberland 138kV line (*CONTINGENCY '228210(UNION)-228262(CUMB)_1'*)
- Reconductor 2.74 miles Sherman-Lincoln 138 kV line
- Sherman substation work
  - Cost Estimate: $0.11M
- Lincoln substation work
  - Cost Estimate: $0.11M
- Cost Estimate: $4.0M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/01/2016



ACE Transmission Zone

Multiple N-1-1 Thermal and N-1-1 Voltage magnitude and drop violations in ACE area are addressed by this set of upgrades

- IS Date 6/1/2015
- Expected IS Date: 6/01/2018-06/01/2019
- Rebuild and reconfigure existing 138 kV line to establish a new New Orchard – Cardiff 230kV line
  - Cost Estimate: $57.0M
- New Upper Pittsgrove – Lewis 138kV line
  - Cost Estimate: $28.0M
- New Cardiff – Lewis #2 138kV line
  - Cost Estimate: $3.5M
- Orchard substation work to accommodate new Orchard – Cardiff 230kV line
  - Cost Estimate: $3.6M
- Upper Pittsgrove substation work
  - Cost Estimate: $0.05M

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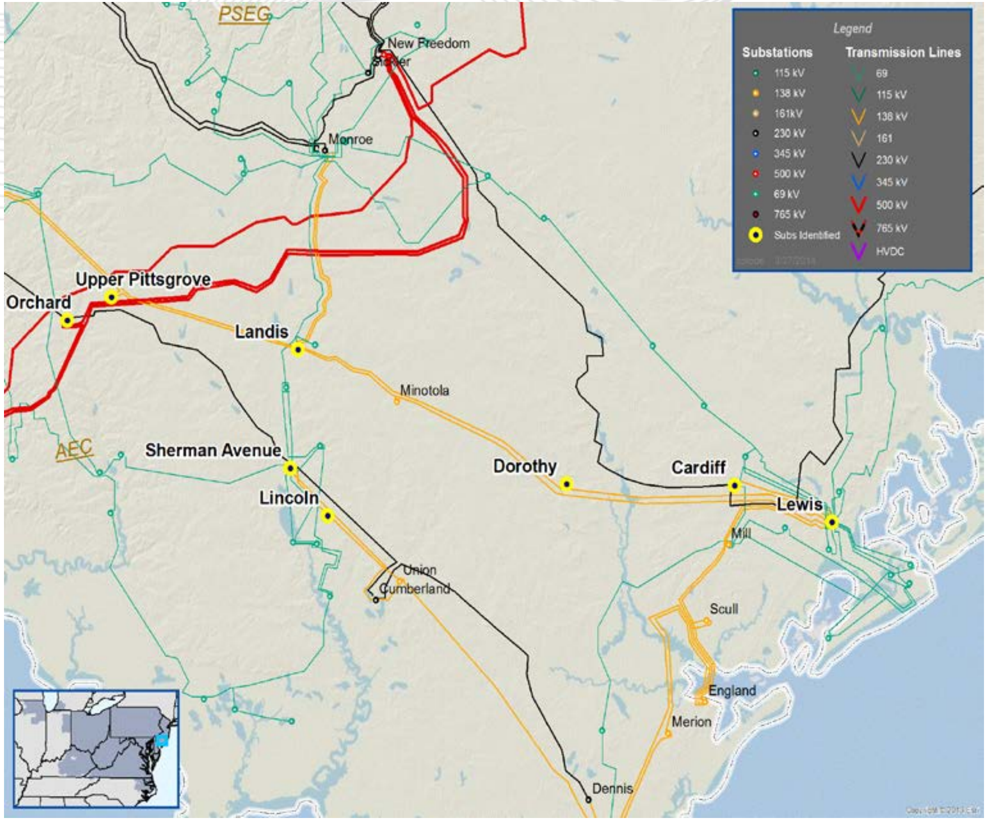
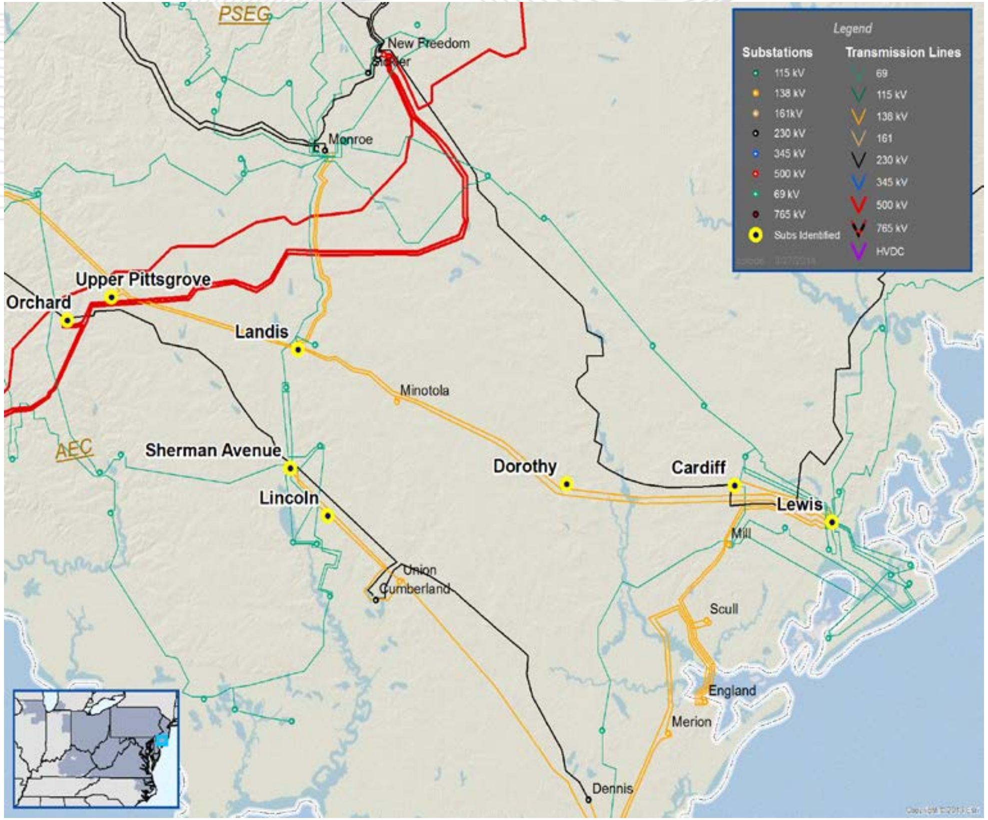


ACE Transmission Zone

Continued from the previous slide:

- Landis substation work to convert Landis to a ring bus and connect 3 lines to it
  - Cost Estimate: $13.4M
- Dorothy substation work – replace two switches with breakers
  - Cost Estimate: $4.0M
- Cardiff substation work to accommodate new Orchard – Cardiff 230kV line and new Cardiff – Lewis 138kV line
  - Cost Estimate: $16.4M
- Lewis substation work
  - Cost Estimate: $0.1M
- Environmental
  - Cost Estimate: $2M

Note: These upgrades will use existing ROW and will also address significant existing age and condition issue of 40 mile 138 kV double circuit tower line.

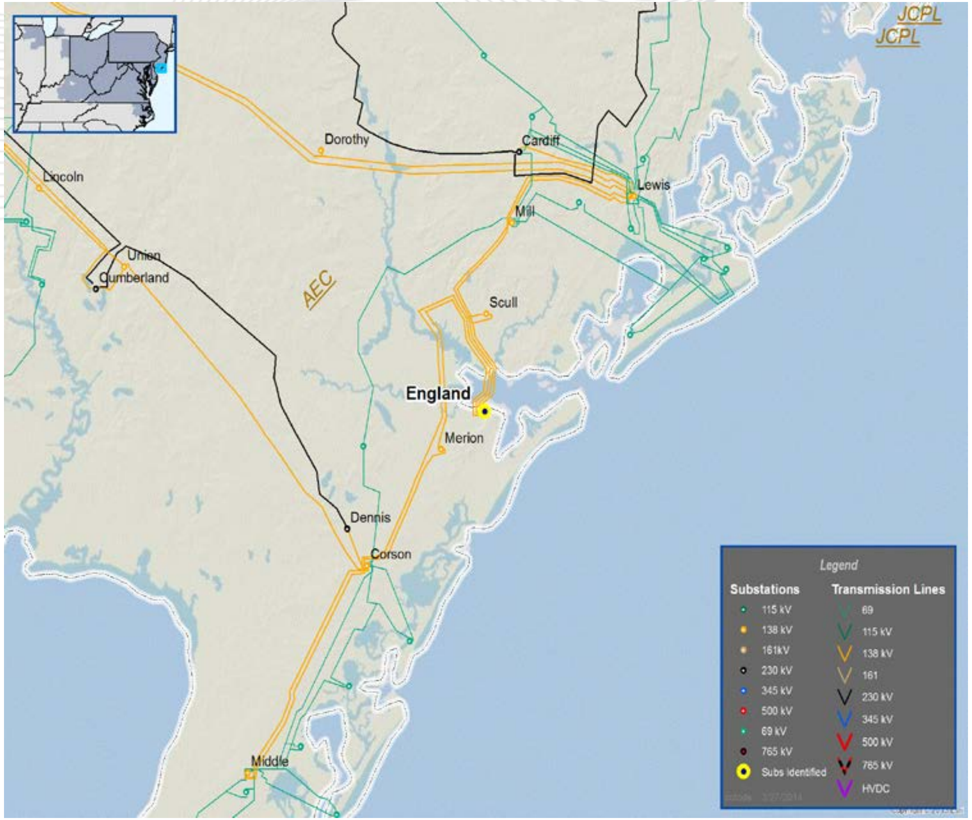


ACE Transmission Zone

- Short term solution to multiple N-1-1 Voltage Violation in ACE area is to install a 100 MVAr capacitor at BLE

- Cost Estimate: $4.0M

- Required IS Date: 6/1/2015
- Expected IS Date: 6/1/2017

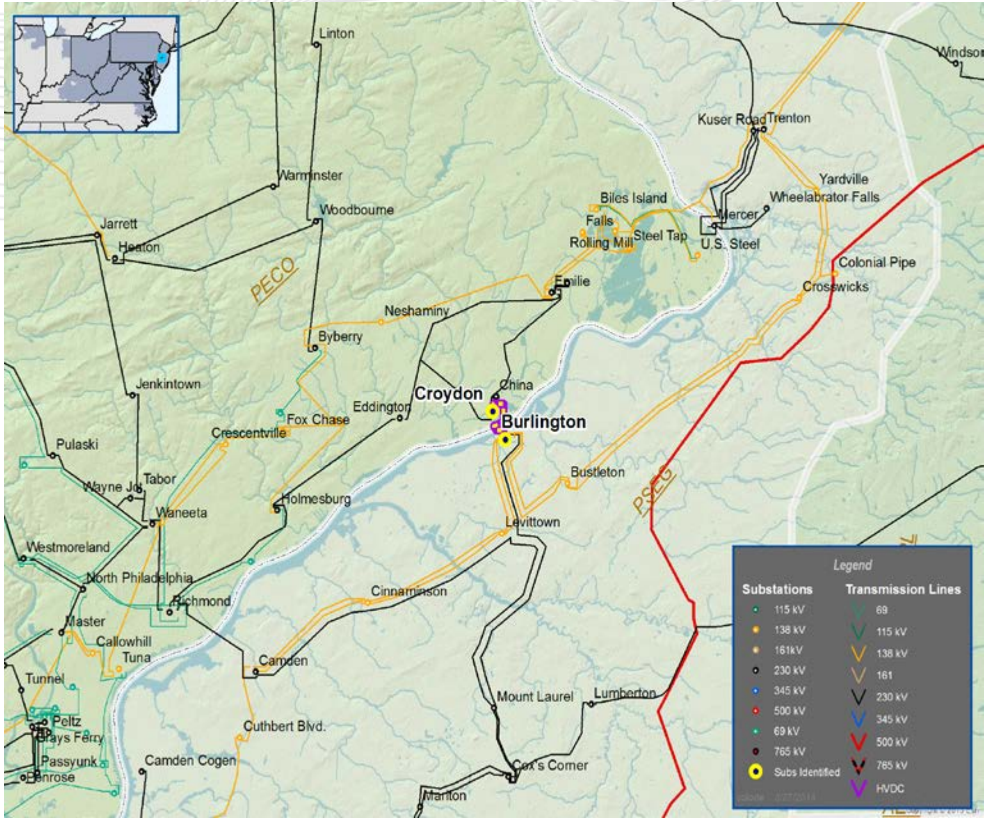


At Risk – BL England Units 2 & 3

PECO Transmission Zone

- **Generator Deliverability Violation**
- Croydon – Burlington 230kV line is overloaded to 107.61%% for the loss of Neshameny 138kV bus (*CONTINGENCY '130-25/* $ BUCKS $ 130-25 $ L'*)
- *Existing baseline upgrades b1197 and b1197.1 – reconductor Croydon – Burlington 230kV line*

- Cost Estimate: $8.6M
- Required IS Date: 6/1/2015
- Expected IS Date: 6/1/2015



Generator At Risk Scenario Study – Next Steps

- Evaluate the impact of the Oyster Creek deactivation along with BL England
  - Study conditions in 2017

Artificial Island Update

Artificial Island
Stability Performance Comparison

Previous Stakeholder Questions

1. Directional Carrier Blocking (DCB) Schemes
2. Performance of PSS/E version 32 vs. PSS/E version 29.
3. SVC performance during a fault and modeling of SVC
4. Performance of SVC on the Delaware Peninsula
5. Market Efficiency of various proposals

Directional Carrier Blocking (DCB) Schemes

- Stakeholder concern: Should PJM reinforce the system as a result of the potential for a carrier blocking relay failure?

- Relay Subcommittee Discussion:
  - Directional Comparison Blocking (DCB) schemes are a widely used and valid communication method to help protect power system equipment. No simulation testing beyond normal criteria analysis is necessary unless there is a need to test beyond criteria (extreme or Type D) contingencies. If DCB schemes do fail they trip more equipment than is necessary in a conservative secure manner.

PSS/E v29 versus PSS/E v32 Benchmarking

- Stakeholder concern: PSS/E v29 produces a different technical result as compared to PSS/E v32
- PJM Findings:
  - PJM consulted with Siemens (the software vendor)
    - Siemens described both the technical differences between v29 and v32 as well as the feedback from the global PSS/E user base
    - There is no technical driver for a benchmarking issue nor has any been reported by the user base, according to Siemens
  - PJM benchmarked PSS/E v29 versus v32 for several scenarios and observed comparable performance
  - Stability results from both versions are valid

PSS/E v29 versus PSS/E v32 Benchmarking

PSS/E ver. 29 case gives comparable results to ver. 32 case.

Current Operational AIOG Case (PSS/E ver. 29)

Group	Project ID	TO	SVC option	AI 500kV bus voltage	Maximum Angle Swing
7.1	P2013_1-5A-SVC	LS Power	Artificial Island	1.044	84
			Orchard	1.043	111
			New Freedom	1.043	115
7.1	P2013_1-2B-SVC	Transource (AEP)	Artificial Island	1.055	86
			Orchard	1.055	113
			New Freedom	1.055	117
7.1	P2013_1-2A-SVC	Transource (AEP)	Artificial Island	1.057	86
			Orchard	1.057	112
			New Freedom	1.057	116
7.1	P2013_1-1B-SVC	DVP	Artificial Island	1.053	83
			Orchard	1.053	110
			New Freedom	1.053	115

AI Order 1000 stability case (PSS/E ver. 32)

Group	Project ID	TO	SVC option	AI 500kV bus voltage	Maximum Angle Swing
7.1	P2013_1-5A-SVC	LS Power	Artificial Island	1.042	80
			Orchard	1.041	108
			New Freedom	1.041	112
7.1	P2013_1-2B-SVC	Transource (AEP)	Artificial Island	1.042	81
			Orchard	1.042	105
			New Freedom	1.042	109
7.1	P2013_1-2A-SVC	Transource (AEP)	Artificial Island	1.043	82
			Orchard	1.042	107
			New Freedom	1.042	112
7.1	P2013_1-1B-SVC	DVP	Artificial Island	1.042	85
			Orchard	1.041	106
			New Freedom	1.041	110

230kV+SVC proposal on PSS/E v29 Case

230kV+SVC options show stable result using the AIOG case in PSS/E ver. 29.

Group	Project ID	TO	Proposed Cost ($)	SVC option	AI 500kV bus voltage	AI MVAr output	Critical Outage	Critical Contingency	Maximum Angle Swing
7.1	P2013_1-5A-SVC	LS Power	$54+SVC	Artificial Island	1.044	636	5015	14b	84
				Orchard	1.043	641	5015	14b	111
				New Freedom	1.043	641	5015	14b	115
7.1	P2013_1-2B-SVC	Transource (AEP)	$165 - $208+SVC	Artificial Island	1.055	623	5015	14b	86
				Orchard	1.055	623	5015	14b	113
				New Freedom	1.055	623	5015	14b	117
7.1	P2013_1-2A-SVC	Transource (AEP)	$213-$269+SVC	Artificial Island	1.057	619	5015	14b	86
				Orchard	1.057	620	5015	14b	112
				New Freedom	1.057	620	5015	14b	116
7.1	P2013_1-1B-SVC	DVP	$126+SVC	Artificial Island	1.053	621	5015	14b	83
				Orchard	1.053	621	5015	14b	110
				New Freedom	1.053	621	5015	14b	115

Note: The study results are obtained under the assumption of unity power factor at the high side of GSU.

SVC Performance During a Fault

- Stakeholder concern: Review PJM assumptions for modeling of SVC performance during a fault.

- PJM Findings:
  - PJM consulted industry experts at EPRI and a SVC hardware manufacturer
  - SVCs can support reactive power during the fault-on period
  - Response speed is fast enough to improve transient stability
  - PSS/E generic SVC models provide a reasonable representation of SVC performance in transient stability studies

SVC Performance on the Delmarva Peninsula

- Stakeholder concern: PJM Should consider an SVC on the Delmarva Peninsula

- PJM Findings:
  - PJM simulated the sensitivity of an SVC on the Delmarva Peninsula and did not observe stable performance for the sensitivity cases.

Artificial Island Constructability Update

Equipment Manufacturer's Feedback

- On-going discussion around SVCs and cable
  - Focus on application, budget level cost and sizing
    - SVC lead time tends to be 18 – 24 months

Salem/Hope Creek Facility Owner Feedback

- Request to minimize outage and physical impacts to existing transmission facilities
- Station licensing documentation will need to be updated based on new configuration. Documentation will need to be submitted to the NRC for approval.
- Existing Hope Creek and Salem substations are within the Owner Controlled Area and subject to Nuclear Security screenings.
  - Increased schedule time and labor costs
- Licensing requirements
  - New lines would need to cross under any station Offsite Power Source.
  - An NRC review and acceptance of the SVC technology and application would be required for an SVC located at Artificial Island
- Detailed design items
  - Maintenance access for station service transformers
  - Limited available access to the Salem substation control house

PJM Operations Review

- 5015 line outage challenges
  - 8 day outage in 2008 is the longest in the last 15 years
  - Numerous instances of curtailed or cancelled outages
- Generation islanding contingency
  - Pre-contingency 230kV overload
- Request to minimize impact to existing transmission facilities
  - RFP goal to reduce operational complexity
- Blackstart
  - 230kV connection provides additional benefit
- Avoid creating any additional NERC Category-D contingencies
  - 500kV line crossings
- Route Diversity

Constructability Review – Project Scope

- PJM Scope Additions in Developing Cost Estimate
  - Submarine Cable
    - Added an installed spare cable
  - Auto-Transformer
    - Added a spare to proposals that included only one bank
  - 500kV Line Crossings
    - Added dead-end structures at 500kV line crossings

Constructability Review – Cost Estimates

- Major components account for 70% - 90% of estimated material and construction costs
  - Submarine cable at $5.3 million per mile
  - 500kV aerial at $3.6 million per mile
  - Aerial Delaware river crossing at $100 million
  - 500/230kV auto transformer at $7.8 to $10.5 million per phase

Constructability Review – Cost Estimates

- Costs independently estimated in collaboration with PJM outside consultants
  - Engineering at 2.5%
  - Project management at 5%
  - Contingency range from 15% to 40%

- Estimate Sources
  - RTEP project cost estimates and actuals
  - Inputs from multiple outside consultants
  - Industry sources

Cost Estimates – Southern Delaware Crossing Lines

	Dominion (VEPCO) Proposal 1B (overhead)	Transource Proposal 2A (submarine)	Transource Proposal 2B (submarine)	LS Power Proposal 5A (submarine)	LS Power Proposal 5A (overhead)
Estimated Costs as Proposed (millions)	• $133	• $213 - $269	• $165 - $208	• $148	• $116
PJM Estimated Costs (millions)	• $233- $283 • Aerial Delaware river crossing • 3 miles 500kV • Six 500/230kV auto-transformers	• $378 - $461 • 5.7 circuit miles of submarine cable (two cables per phase plus one spare cable) • Six 500/230kV auto-transformers	• $264 - $321 • 3.6 circuit miles of submarine cable (two cables per phase plus one spare cable) • Six 500/230kV auto-transformers	• $256 - $311 • 3.3 circuit miles of submarine cable (two cables per phase plus one spare cable) • Four 500/230kV auto-transformers	• $211- $257 • Aerial Delaware river crossing • Four 500/230kV auto-transformers

Cost Estimates – Artificial Island to Red Lion Lines

	Dominion (VEPCO) Proposal 1C	PSE&G Proposal 7K	PHI / Exelon Proposal 4A	LS Power Proposal 5B	Transource Proposal 2C
Estimated Costs as Proposed (millions)	• $199	• $297	• $181	• $171	• $123 - $156
PJM Estimated Costs (millions)	• $242 - $294 • Aerial Delaware river crossing • 15.1 miles 500kV (includes aerial Salem-Hope Creek tie)	• $249 - $304 • Aerial Delaware river crossing • 14.6 miles 500kV	• $216 - $263 • Aerial Delaware river crossing • 14.6 miles 500kV	• $221 - $269 • Aerial Delaware river crossing • 14.6 miles 500kV	• $232 - $282 • Aerial Delaware river crossing • 14.6 miles 500kV

Schedule Risk Factors

	Southern Delaware Line Crossing Projects	
	Submarine River Crossing	**Overhead River Crossing**
Schedule Risk Factors	• Environmental permitting • (Transource) Relocation of 5024 line requires Salem expansion • Submarine cable lead time	• Public opposition / Permitting risk for the Delaware river crossing • (Dominion) - Salem interconnection coordination risk due to generator lead proximity
Common Factors	• Route cannot be finalized until permitting is complete • Salem expansion requires two bus outages for final tie-in • Crossing Delaware state route 9, which is a ‘Scenic and Historic Highway’ may impact permitting • Construction is approximately 2 years and does not appear to be a major schedule risk	

Schedule Risk Factors

	Dominion (VEPCO) Proposal 1C	PSE&G Proposal 7K	PHI / Exelon Proposal 4A	LS Power Proposal 5B	Transource Proposal 2C

Common Factors	• Route parallels existing 5015 line
	  • Permitting process
	  • Delaware River Crossing
	  • Supawna Meadows National Wildlife Refuge
	• All include an attachment into Salem and Red Lion substations
	• Construction is approximately 2 years and does not appear to be a major schedule risk
	  • All projects require at least one 500kV line crossing
	  • All projects require a 5015 line outage				

Schedule Risk Factors

	Dominion (VEPCO) Proposal 1C	PSE&G Proposal 7K	PHI / Exelon Proposal 4A	LS Power Proposal 5B	Transource Proposal 2C
Schedule Risk Factors	• Significant 5015 line outages required for Red Lion expansion and line crossing • Salem and Hope Creek tie coordination risk due to generator lead proximity	• Significant 5015 line outages required for Red Lion expansion and line crossing • 5037 relocation outage impact to Hope Creek substation • Salem and Hope Creek tie risk due to Salem generator lead proximity	• 5015 line outage required for Red Lion expansion and tie-in to new bay • Outages required to raise 5023, 5024, and 5021 lines to allow for crossing	• 5015 line outage required for Red Lion expansion and tie-in to new bay • Relocation of 5037 line requires Salem expansion • Outages required to raise 5023 and 5015 lines to allow for crossing	• 5015 line outage required for Red Lion expansion • Relocation of 5024 line requires Salem expansion • Relocation of 5021 line requires • Outage required to raise 5023 line to allow for crossing

SVCs

- SVC Locations:
  - New Freedom
  - Orchard
- Schedule Estimate 36 months
  - SVC lead time of 24 months
  - Permitting and land acquisition 6 months
- Cost Estimate $80 million
  - SVC $60 million

Artificial Island Timeline

- Next Steps
- May 2014 – Artificial Island recommendation at PJM TEAC
- July 2014 – PJM staff to submit recommendation to the PJM Board

Questions?

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Revision History

- 4/7/2014 v1
  - Original version distributed to PJM TEAC
- 4/9/2014
  - Updated expected in-service dates on slides 25 & 27