Calvert Cliffs Nuclear Power Plant

1650 Calvert Cliffs Parkway
Lusby, Maryland 20657

Constellation Energy
Nuclear Generation Group

December 29, 2008

U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318
Response to Request for Additional Information – License Amendment for Measurement Uncertainty Recapture Power Uprate - Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2

REFERENCES:

(a) Letter from Mr. D. R. Bauder (CCNPP), to Document Control Desk (NRC) dated August 29, 2008, License Amendment Request: Appendix K Measurement Uncertainty Recapture – Power Uprate Request

(b) Letter from Mr. D. V. Pickett (NRC) to Mr. J. A. Spina (CCNPP), dated November 04, 2008, Request for Additional Information Re: License Amendment for Measurement Uncertainty Recapture Power Uprate- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2

In Reference (a), Calvert Cliffs Nuclear Power Plant, Inc. submitted a license amendment request to the Nuclear Regulatory Commission (NRC) for a measurement uncertainty recapture power uprate for Calvert Cliffs Nuclear Power Plant, Units 1 and 2. In Reference (b) the NRC requested additional information to be submitted to support their review of the submittal. Our response to this request is attached.

A001
NRR

Should you have any questions regarding this matter, please contact Mr. Jay S. Gaines at (410) 495-5219.

Very truly yours,

Mark D. Flaherty

STATE OF MARYLAND :
: **TO WIT:**
COUNTY OF CALVERT :

I, Mark D. Flaherty, being duly sworn, state that I am Manager – Engineering Services, Calvert Cliffs Nuclear Power Plant, Inc. (CCNPP), and that I am duly authorized to execute and file this License Amendment Request on behalf of CCNPP. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other CCNPP employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Mark D. Flaherty

Subscribed and sworn before me, a Notary Public in and for the State of Maryland and County of St. Marys, this 29th day of December, 2008.

WITNESS my Hand and Notarial Seal:

Janet L. Scally
Notary Public

My Commission Expires:

March 1, 2011
Date

MDF/KLG/bjd

Attachment: (1) Response to Request for Additional Information - Measurement Uncertainty Recapture Power Uprate

cc: D. V. Pickett, NRC
S. J. Collins, NRC
Resident Inspector, NRC
S. Gray, DNR

ATTACHMENT (1)

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION -

MEASUREMENT UNCERTAINTY RECAPTURE POWER UPRATE

Calvert Cliffs Nuclear Power Plant, Inc.
December 29, 2008

RAI 1:

Provide the maximum value in megawatts electric (MWe) for the existing and uprated power level for Calvert Cliffs Units 1 and 2.

CCNPP Response:

Calvert Cliffs maximum expected Summer Gross MWe generation:

	Existing	Uprated
Unit 1	896	908
Unit 2	885	897

These values are the maximum theoretical MWe increase expected due to the Measurement Uncertainty Recapture (MUR) uprate. Actual uprated values will be determined after a period of operation at the increased MUR power uprate value of 2737 MW_T.

RAI 2:

In Section V.4 of Attachment 2 of the license amendment request, the licensee states that the Pennsylvania, New Jersey, Maryland Interconnection has preliminarily reviewed the power uprate for impacts and grid stability and concludes that the proposed electrical output will not have any effect on grid stability or reliability. Provide details of the grid stability study and discuss in depth the assumptions, methodology, cases studied, and evidence to support the aforementioned conclusion.

CCNPP Response:

Since the Pennsylvania, New Jersey, Maryland Interconnection's (PJM) preliminary review, they have performed both an interim impact study (Enclosure 1) and a final impact study (Enclosure 2). These studies bound the expected increase in MWe due to the MUR uprate that is indicated in the response to RAI 1 above.

Also attached is a copy of the PJM Systems Dynamics Working Group procedure manual (Enclosure 3) and the PJM Manual 14B (Enclosure 4 contains only Section 2 of PJM Manual 14B as Section 2 is the applicable portion of the manual. PJM Manual 14B can be viewed in its entirety at www.pjm.com/documents/manual.aspx). These two manuals provide details of the inputs, assumptions, methodology, cases studied, and supporting evidence for the conclusions listed in the "Network Impacts" section of Enclosures 1 and 2.

RAI 3:

For the power uprate of 1.38%, please identify the nature and quantity of megavolt ampere reactive (MVAR) support necessary to maintain post-trip loads and minimum voltage levels. Also address how the power uprate would affect MVAR support. Are there any compensatory measures the licensee would take to address the potential depletion of the nuclear unit's MVAR capability on a grid-wide basis as a result of the power uprate?

CCNPP Response:

The final impact study (Enclosure 2) contains the maximum MVAR capability used in the PJM model. This capability is within the main generator's D-curve ratings. Since no problems were identified in Enclosure 2, no compensatory measures are necessary.

RAI 4:

Provide a detailed comparison of existing ratings with uprated ratings and the effect of the power uprate on the plant service transformers.

CCNPP Response:

For the Calvert Cliffs electrical auxiliary power system, the MUR uprate will only impact a small number of non-safety-related 4 kV motors by increasing the pump brake horsepower to support increased flow requirements. The combined increased horsepower required results in a maximum anticipated 87 kVA and 77 kVA total load increase to the plant electrical system for Unit Nos. 1 and 2, respectively.

The Calvert Cliffs plant service transformers are rated 500/14 kV, 3 phase, 60 Hz, 100 MVA. The transformers and associated 13 kV and 4 kV electrical systems are designed such that the entire service load from both Unit Nos. 1 and 2 can be aligned through one service transformer. In this case, maximum calculated load is expected to increase from its current value of 96.7 MVA, to a value of 96.87 MVA with the addition of the MUR related additional load. This is within the transformer 100 MVA rating.

ENCLOSURES

1. Generator Interconnection #K27/M04 Calvert Cliffs 55 MW Interim Impact Study, May 2004
2. Generator Interconnection # M04 Calvert Cliffs 55 MW Impact Study, November 2005
3. PJM System Dynamics Working Group Procedure Manual, February 2006
4. PJM Manual 14B: PJM Region Transmission Planning Process, Section 2, Revision 12, Effective Date: 08/08/2008

ENCLOSURE (1)

Generator Interconnection #K27/M04 Calvert Cliffs 55 MW Interim Impact Study, May 2004

Calvert Cliffs Nuclear Power Plant, Inc.
December 29, 2008

Generator Interconnection #K27/M04 Calvert Cliffs 55 MW Interim Impact Study

May 2004
Docs #265080

General

Queues K27 (35 MW) and M04 (100 MW) are Constellation Power Source, Inc. requests for interconnection of an additional 135 MWs (summer capacity) at Calvert Cliffs associated with the following uprates:

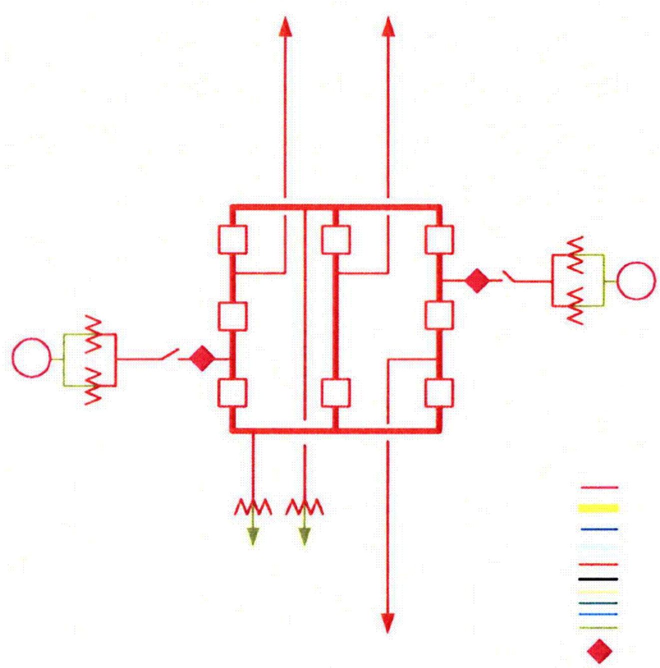
	Uprate	Unit 1	Unit 2
June 2004	#1 Steam Gen Replacement	**21 MW**	-
June 2004	#1 LP Turbine Replacement	**62 MW**	-
June 2004	#2 Steam Generator Replacement	-	**25 MW**
December 2004	#1 Appendix K	**12 MW**	-
June 2005	#2 Appendix K	-	12 MW
		95 MW	37 MW

This **Interim Impact Study (May 2004 to June 1, 2005)** addresses the requirements for Interim Capacity Interconnection Rights (CIRs) of 55 MW. which is scheduled to be in-service in 2004 prior to the completion of a final Impact Study for Queue positions K27 and M04.

Calvert Cliffs Nuclear Plant is located in Lusby, Calvert County, Maryland.

Direct Connection Requirements

Queues K27/M04 uprates of existing Calvert Cliffs Units #1 and #2 does not require new or upgraded Direct Connection facilities. The existing Unit #1 and #2 connection is shown on the one line diagram below.



Power Factor Requirements (at 55 MW Interim increase level)

PJM OATT Section 57.4.1 requires that "A Generation Interconnection Customer shall design its Customer Facility to maintain a composite power delivery at continuous rated power output at the generator's terminals at a power factor of at least 0.95 leading to 0.90 lagging".

Calvert Cliffs Unit 1 can receive a maximum interim increase of 35 MW CIR if the reactive capability in EDart is updated and maintained at a 367 MVAR value. Any additional capacity increase will require installation of reactive resources to maintain a 0.90 lagging power factor.

Calvert Cliffs Unit 2 can receive an increase of 20 MW based on the grandfathered reactive capability design in accordance with PJM's Business Rule which waives PJM OATT Section 57.4.1 requirements for MW increases of 20 MW or less to existing (grandfathered) generation facilities. Any additional capacity increase will require installation of reactive resources to maintain a 0.90 lagging power factor.

Network Impacts

The Calvert Cliffs Queue **K27/M04 Interim Interconnection was studied as 55 MW capacity** increase to Calvert Cliffs Units #1 (20MW) and #2 (35MW). Queues K27/M04 were evaluated for compliance with reliability criteria for summer peak conditions in **2004**. Potential network impacts were as follows:

Generator Deliverability
No problems identified.

Multiple Facility Contingency – Tower Line Outages (MAAC Criteria IIC)
No problems identified.

Short Circuit
No problems identified.

The planned Unit 2 uprates do not change the generator impedance; however, there was a change of impedance for the Unit #1 generator, and Units #1 and #2 generator step-up transformers were replaced with GSUs having a differant impedance.

Stability Analysis (MAAC Criteria IV)

No problems identified.

Stability analysis was performed at light load conditions and for maximum summer generator output with the proposed plant uprates of 55 MW associated with K27 and M04 queue projects. See Attachment #1 for the fault cases evaluated. The range of contingencies evaluated was limited to that necessary to demonstrate compliance with MAAC reliability criteria.

Note: While the stability analysis has been performed at expected extreme system conditions, there is a potential that evaluation at different level of generator MW and/or MVAR output at different load levels and operating conditions would disclose unforeseen stability problems. The regional reliability analysis routinely performed to test all system changes will include one such evaluation. Any problems uncovered in this or other operating or planning studies will need to be resolved.

Stability analysis was performed at light load conditions and for maximum summer generator output with the proposed plant uprates associated with the K27 and M04 queue projects. See Attachment #1 for the fault cases evaluated. The range of contingencies evaluated was limited to that necessary to demonstrate compliance with MAAC reliability criteria

New System Reinforcements
None required.

Contribution to Previously Identified System Reinforcements
None.

ATTACHMENT #1

Stability Analysis Results

CALVERT CLIFFS K27 and M04 (55MW Interim Impact Study)

Breaker Clearing Times (cycles)

Station	Primary (3ph/slg)	Stuck Breaker timer (total)
All BGE 500 kV	4.5	13
All PEPCO 500 kV	4.2	12.1

Criteria Test Faults (All stable)

K27-1a 3ph @ Calvert Cliffs 500 KV on Calvert Cliffs-Chalk Point 500 KV
K27-1b slg @ Calvert Cliffs 500 KV on Calvert Cliffs-Chalk Point 500 KV, stuck @ Calvert Cliffs

K27-2a 3ph @ Calvert Cliffs 500 KV on Calvert Cliffs-Waugh Chapel 500 KV ckt1
K27-2b slg @ Calvert Cliffs 500 KV on Calvert Cliffs-Waugh Chapel 500 KV ckt1 , stuck @ Calvert Cliffs

K27-3a 3ph @ Calvert Cliffs 500 KV on Calvert Cliffs-Waugh Chapel 500 KV ckt2
K27-3b slg @ Calvert Cliffs 500 KV on Calvert Cliffs-Waugh Chapel 500 KV ckt2 , stuck @ Calvert Cliffs

K27-4a 3ph @ Chalk Point 500 KV on Chalk Point-Possum Point 500 KV
K27-4b slg @ Chalk Point 500 KV on Chalk Point-Possum Point 500 KV, stuck @ Chalk Point

K27-5a 3ph @ Chalk Point 500 KV on Chalk Point 500/230 KV TX1
K27-5b slg @ Chalk Point 500 KV on Chalk Point 500/230 KV TX1, stuck @ Chalk Point

K27-6a 3ph @ Possum Point 500 KV on Possum Point-Ladysmith 500 KV
K27-6b slg @ Possum Point 500 KV on Possum Point- Ladysmith 500 KV, stuck @ Possum Point

K27-7a 3ph @ Possum Point 500 KV on Possum Point-OX 500 KV
K27-7b slg @ Possum Point 500 KV on Possum Point- OX 500 KV, stuck @ Possum Point

K27-8a 3ph @ Waugh Chapel 500KV on Waugh Chapel-Brighton 500 KV
K27-8b slg @ Waugh Chapel 500KV on Waugh Chapel-Brighton 500 KV, stuck @ Waugh Chapel

Additional Test Faults (All Stable)

K27p-2a same as K27-2a with Chalk Point-Calvert Cliffs 500 KV O/S on maintenance
K27p-2b same as K27-2b with Chalk Point-Calvert Cliffs 500 KV O/S on maintenance
K27p-3a same as K27-3a with Chalk Point-Calvert Cliffs 500 KV O/S on maintenance
K27p-3b same as K27-3b with Chalk Point-Calvert Cliffs 500 KV O/S on maintenance

K27q-1a same as K27-1a with Calvert Cliffs- Waugh Chapel 500 KV ckt1 O/S on maintenance
K27q-1b same as K27-1b with Calvert Cliffs- Waugh Chapel 500 KV ckt1 O/S on maintenance
K27q-3a same as K27-3a with Calvert Cliffs- Waugh Chapel 500 KV ckt1 O/S on maintenance
K27q-3b same as K27-3b with Calvert Cliffs- Waugh Chapel 500 KV ckt1 O/S on maintenance

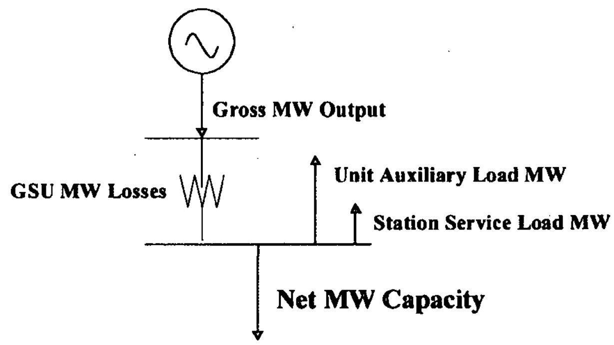
K27r-1a same as K27-1a with Chalk Point-Possum Point 500 KV O/S on maintenance
K27r-1b same as K27-1b with Chalk Point-Possum Point 500 KV O/S on maintenance
K27r-2a same as K27-2a with Chalk Point-Possum Point 500 KV O/S on maintenance
K27r-2b same as K27-2b with Chalk Point-Possum Point 500 KV O/S on maintenance
K27r-3a same as K27-3a with Chalk Point-Possum Point 500 KV O/S on maintenance
K27r-3b same as K27-3b with Chalk Point-Possum Point 500 KV O/S on maintenance

K27s-1a same as K27-1a with Chalk Point 500/230 KV TX1 O/S on maintenance
K27s-1b same as K27-1b with Chalk Point 500/230 KV TX1 O/S on maintenance
K27s-2a same as K27-2a with Chalk Point 500/230 KV TX1 O/S on maintenance
K27s-2b same as K27-2b with Chalk Point 500/230 KV TX1 O/S on maintenance
K27s-3a same as K27-3a with Chalk Point 500/230 KV TX1 O/S on maintenance
K27s-3b same as K27-3b with Chalk Point 500/230 KV TX1 O/S on maintenance

ATTACHMENT #2

(Generator and GSU Data)

Unit Capability Data



Net MW Capacity = (Gross MW Output - GSU MW Losses* – Unit Auxiliary Load MW - Station Service Load MW)

Queue Letter/Position/Unit ID: ________________K27 and M04 (Calvert Cliff unit1)

Primary Fuel Type: ____Nuclear

Maximum Summer (92° F ambient air temp.) Net MW Output**: _____________ 873

Maximum Summer (92° F ambient air temp.) Gross MW Output:______________ 908

Minimum Summer (92° F ambient air temp.) Gross MW Output: _________________

Maximum Winter (30° F ambient air temp.) Gross MW Output: _________________

Minimum Winter (30° F ambient air temp.) Gross MW Output: _________________

Gross Reactive Power Capability at Maximum Gross MW Output – Please include
Reactive Capability Curve (Leading and Lagging): 367 MVAR lagging, -50 MVAR leading

Individual Unit Auxiliary Load at Maximum Summer MW Output (MW/MVAR): ____

Individual Unit Auxiliary Load at Minimum Summer MW Output (MW/MVAR): _____

Individual Unit Auxiliary Load at Maximum Winter MW Output (MW/MVAR): ______

Individual Unit Auxiliary Load at Minimum Winter MW Output (MW/MVAR): ______

Station Service Load (MW/MVAR): __________70 MW spread evenly over the 2 units

* GSU losses are expected to be minimal.
** Your project's declared MW, as first submitted in Attachment N, and later confirmed or modified by the Impact Study Agreement, should be based on either the 92° F Ambient Air Temperature rating of the unit(s) or, if less, the declared Capacity rating of your project.

Unit Generator Dynamics Data

Queue Letter/Position/Unit ID: ________________ K27 and M04 (Calvert Cliffs unit1)

MVA Base (upon which all reactances, resistance and inertia are calculated): _____ 1020

Nominal Power Factor: ________________ 0.9

Terminal Voltage (kV): ________________ 25

*Unsaturated Reactances **(on MVA Base)***

Direct Axis Synchronous Reactance, $X_{d(i)}$: ________________ 1.61

Direct Axis Transient Reactance, X'd(i): ________________ 0.355

Direct Axis Sub-transient Reactance, X"d(i): ________________ 0.280

Quadrature Axis Synchronous Reactance, Xq(i): ________________ 1.51

Quadrature Axis Transient Reactance, X'q(i): ________________ 0.557

Quadrature Axis Sub-transient Reactance, X"q(i): ________________ 0.280

Stator Leakage Reactance, Xl: ________________ 0.21

Negative Sequence Reactance, X2(i): ________________ 0.235

Zero Sequence Reactance, X0: ________________ 0.190

Saturated Sub-transient Reactance, X"d(v) (on MVA Base): ________________ 0.235

Armature Resistance, Ra (on MVA Base): ________________

Time Constants (seconds)

Direct Axis Transient Open Circuit, T'_{do}: ________________ 6.771

Direct Axis Sub-transient Open Circuit, T''_{do}: ________________ 0.031

Quadrature Axis Transient Open Circuit, T'_{qo}: ________________ 0.385

Quadrature Axis Sub-transient Open Circuit, T''_{qo}: ________________ 0.053

Inertia, H (kW-sec/kVA, on KVA Base): ________________ 4.395

Speed Damping, D: ________________ 0

Saturation Values at Per-Unit Voltage [S(1.0), S(1.2)]: ________________ 0.1, 0.44

Units utilize a GENROU Generator model

Unit GSU Data

Queue Letter/Position/Unit ID:__________________K27 and M04 (Calvert Cliffs unit1)

Generator Step-up Transformer MVA Base: ___Two 810 MVA TX connected in parallel

Generator Step-up Transformer Impedance (%, on transformer MVA Base): __20.55% (both)

Generator Step-up Transformer Rating (MVA):______________________________810.0

Generator Step-up Transformer Low-side Voltage (kV): ________________________25.0

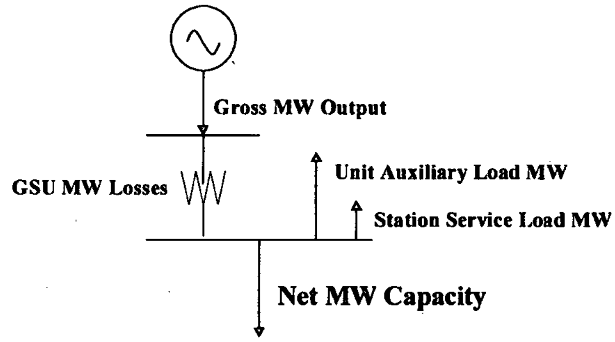
Generator Step-up Transformer High-side Voltage (kV):_______________________500.0

Generator Step-up Transformer Off-nominal Turns Ratio:_______________________1.05

Generator Step-up Transformer Number of Taps and Step Size: ___3 taps of 2.5 % above

And 1 tap of 2.5% below

Unit Capability Data



Net MW Capacity = (Gross MW Output - GSU MW Losses* – Unit Auxiliary Load MW - Station Service Load MW)

Queue Letter/Position/Unit ID: __________ K27 and M04 (Calvert Cliff unit2)

Primary Fuel Type: __________ Nuclear

Maximum Summer (92° F ambient air temp.) Net MW Output**: __________ 867

Maximum Summer (92° F ambient air temp.) Gross MW Output: __________ 902

Minimum Summer (92° F ambient air temp.) Gross MW Output: __________

Maximum Winter (30° F ambient air temp.) Gross MW Output: __________

Minimum Winter (30° F ambient air temp.) Gross MW Output: __________

Gross Reactive Power Capability at Maximum Gross MW Output – Please include Reactive Capability Curve (Leading and Lagging):350 MVAR lagging, -50 MVAR leading

Individual Unit Auxiliary Load at Maximum Summer MW Output (MW/MVAR): ____

Individual Unit Auxiliary Load at Minimum Summer MW Output (MW/MVAR): ____

Individual Unit Auxiliary Load at Maximum Winter MW Output (MW/MVAR): ____

Individual Unit Auxiliary Load at Minimum Winter MW Output (MW/MVAR): ____

Station Service Load (MW/MVAR): __________ 70 MW spread evenly over the 2 units

* GSU losses are expected to be minimal.

** Your project's declared MW, as first submitted in Attachment N, and later confirmed or modified by the Impact Study Agreement, should be based on either the 92° F Ambient Air Temperature rating of the unit(s) or, if less, the declared Capacity rating of your project.

Unit Generator Dynamics Data

Queue Letter/Position/Unit ID: ________________K27 and M04 (Calvert Cliff unit2)

MVA Base (upon which all reactances, resistance and inertia are calculated): _____ 1003

Nominal Power Factor: ________________

Terminal Voltage (kV): ________________22.0

*Unsaturated Reactances **(on MVA Base)***

Direct Axis Synchronous Reactance, $X_{d(i)}$: ________________1.599

Direct Axis Transient Reactance, X'd(i): ________________0.442

Direct Axis Sub-transient Reactance, X"d(i): ________________0.301

Quadrature Axis Synchronous Reactance, Xq(i): ________________1.561

Quadrature Axis Transient Reactance, X'q(i): ________________0.682

Quadrature Axis Sub-transient Reactance, X"q(i): ________________0.301

Stator Leakage Reactance, Xl: ________________0.2250

Negative Sequence Reactance, X2(i): ________________

Zero Sequence Reactance, X0: ________________

Saturated Sub-transient Reactance, X"d(v) (on MVA Base): ________________

Armature Resistance, Ra (on MVA Base): ________________

Time Constants (seconds)

Direct Axis Transient Open Circuit, T'_{do}: ________________5.95

Direct Axis Sub-transient Open Circuit, T''_{do}:_ ________________0.035

Quadrature Axis Transient Open Circuit, T'_{qo}:_ ________________1.5

Quadrature Axis Sub-transient Open Circuit, T''_{qo}: ________________0.07

Inertia, H (kW-sec/kVA, on KVA Base): ________________3.346

Speed Damping, D: ________________ 0

Saturation Values at Per-Unit Voltage [S(1.0), S(1.2)]: ________________ 0.096, 0.3133

Units utilize a Genrou Generator model

Unit GSU Data

Queue Letter/Position/Unit ID:____________________K27 and M04 (Calvert Cliff unit2)

Generator Step-up Transformer MVA Base: ___Two 810 MVA TX connected in parallel

Generator Step-up Transformer Impedance (%, on transformer MVA Base):20.94% and 20.88%

Generator Step-up Transformer Rating (MVA):_____________________________810.0

Generator Step-up Transformer Low-side Voltage (kV): ________________________22.0

Generator Step-up Transformer High-side Voltage (kV):_______________________500.0

Generator Step-up Transformer Off-nominal Turns Ratio:_______________________1.05

Generator Step-up Transformer Number of Taps and Step Size: ___3 taps of 2.5 % above
And 1 tap of 2.5% below

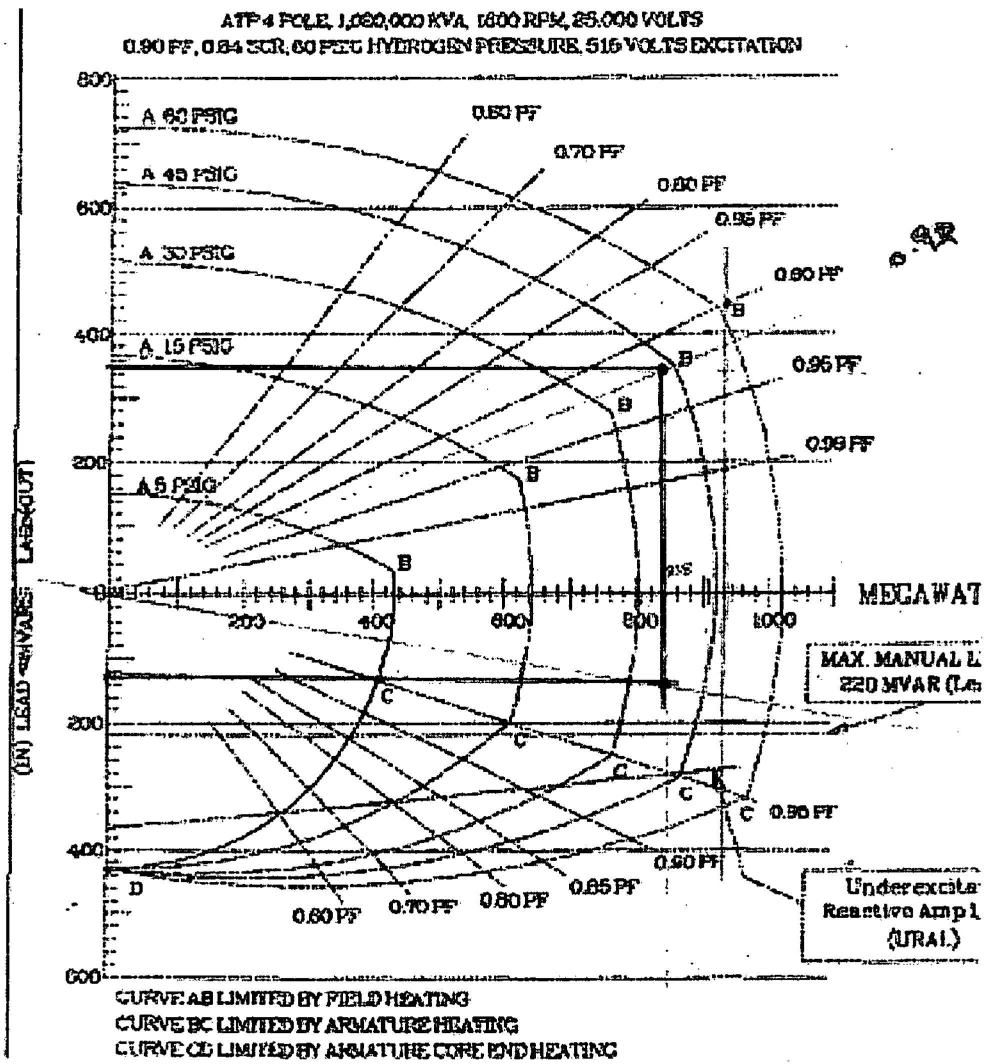
ATTACHMENT #3

Units #1 and #2 Capability Curves

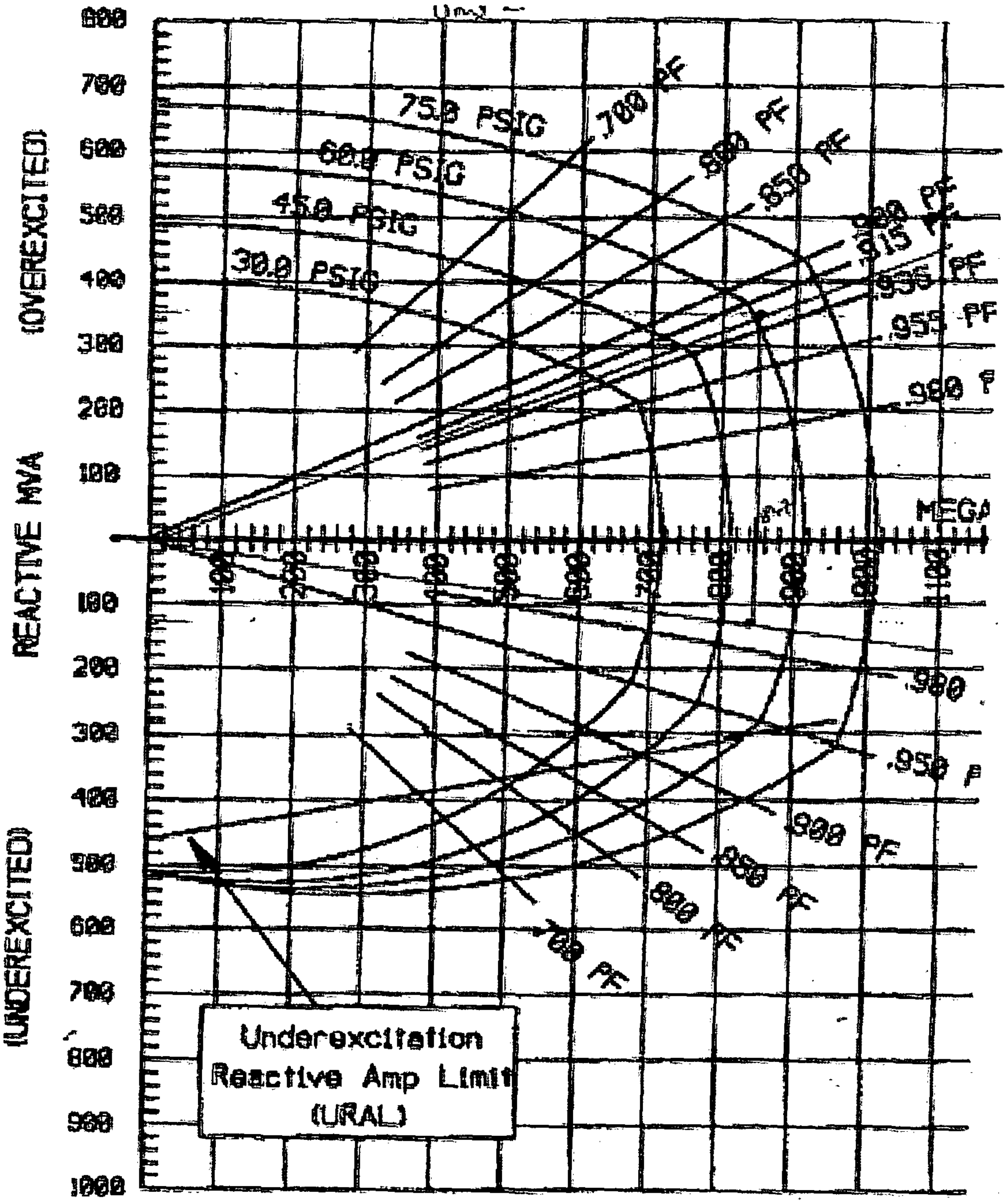
Unit #1

1. **WHEN** the Voltage Regulator is in MANUAL,
   THEN the steady-state Reactive Load shall **NOT** exceed 220 MVAR (LI
   [B0219]

Unit 1



Unit #2



REACTIVE MVA
(OVEREXCITED)
(UNDEREXCITED)
75.0 PSIG
60.0 PSIG
45.0 PSIG
30.0 PSIG
.700 PF
.800 PF
.850 PF
.900 PF
.915 PF
.935 PF
.955 PF
.980 PF
.980
.950
.900 PF
.850 PF
.800 PF
.700 PF
MEGA
Underexcitation
Reactive Amp Limit
(URAL)

ENCLOSURE (2)

Generator Interconnection # M04 Calvert Cliffs 55 MW Impact Study,

November 2005

Calvert Cliffs Nuclear Power Plant, Inc.
December 29, 2008

Generator Interconnection #M04 Calvert Cliffs 55 MW Impact Study

November 2005
Docs #319683

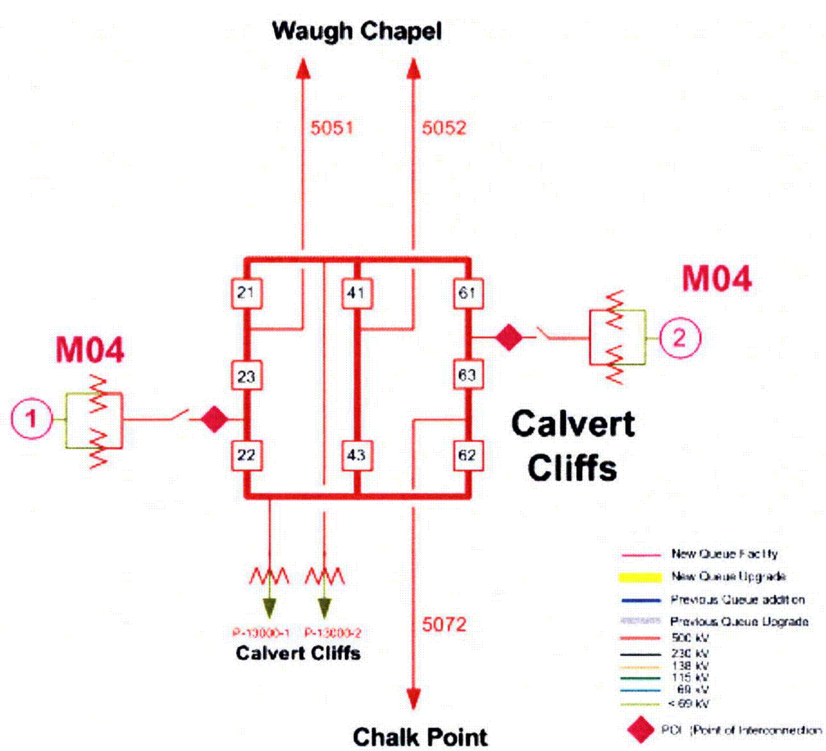
General

Queue M04 is a Constellation Power Source, Inc. request for interconnection of an additional 55 MWs Capacity at Calvert Cliffs 500 kV station. The scheduled increase to Calvert Cliffs units 1 and 2 are expected to be complete in 2005.

	Uprate	Unit 1	Unit 2
2002-03	#1 Steam Gen Replacement	X	-
2004	#1 LP Turbine Replacement	X	-
2004	#2 Steam Generator Replacement	-	X
2004	#1 Appendix K	X	-
2005	#2 Appendix K	-	X

Direct Connection Requirements

Queue M04 uprates of existing Calvert Cliffs Units #1 and #2 does not require new or upgraded Direct Connection facilities. The existing Unit #1 and #2 connection is shown on the one line diagram below.



Power Factor Requirements

PJM OATT Section 57.4.1 requires that "A Generation Interconnection Customer shall design its Customer Facility to maintain a composite power delivery at continuous rated power output at the generator's terminals at a power factor of at least 0.95 leading to 0.90 lagging".

Calvert Cliffs Unit 1 can receive a maximum increase of 35 MW CIR if the reactive capability in EDart is updated and maintained at a 367 MVAR value. Any additional capacity increase will require installation of reactive resources to maintain a 0.90 lagging power factor.

Calvert Cliffs Unit 2 can receive an increase of 20 MW based on the grandfathered reactive capability design in accordance with PJM's Business Rule which waives PJM OATT Section 57.4.1 requirements for MW increases of 20 MW or less to existing (grandfathered) generation facilities. Any additional capacity increase will require installation of reactive resources to maintain a 0.90 lagging power factor.

Network Impacts

Calvert Cliffs Queue **M04 was studied as a 55 MW capacity** increase to Calvert Cliffs Units #1 and #2 and evaluated for compliance with reliability criteria for summer peak conditions in **2009.** Potential network impacts were as follows:

Generator Deliverability
No problems identified.

Multiple Facility Contingency – Tower Line Outages (MAAC Criteria IIC)
No problems identified.

Local System Impacts
No problems identified.

Short Circuit
No problems identified for this Queue position.

Stability Analysis
No problems identified

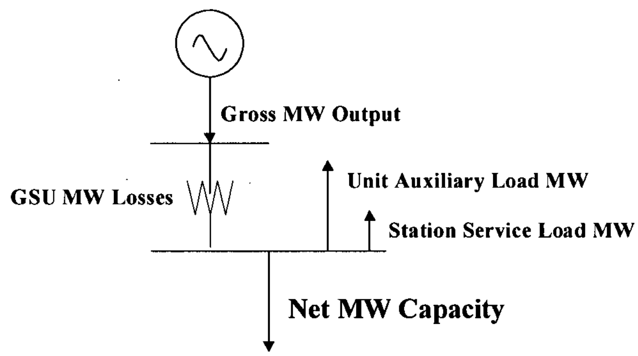
New System Reinforcements
None.

Contribution to Previously Identified System Reinforcements
None.

ATTACHMENT #1

(Generator and GSU Data)

Unit Capability Data



Net MW Capacity = (Gross MW Output - GSU MW Losses* – Unit Auxiliary Load MW - Station Service Load MW)

Queue Letter/Position/Unit ID: ________________________ M04 (Calvert Cliff unit1)

Primary Fuel Type: ____ Nuclear

Maximum Summer (92° F ambient air temp.) Net MW Output**: ____________ 873

Maximum Summer (92° F ambient air temp.) Gross MW Output: ____________ 908

Minimum Summer (92° F ambient air temp.) Gross MW Output: ______________

Maximum Winter (30° F ambient air temp.) Gross MW Output: _______________

Minimum Winter (30° F ambient air temp.) Gross MW Output: ________________

Gross Reactive Power Capability at Maximum Gross MW Output – Please include Reactive Capability Curve (Leading and Lagging): 367 MVAR lagging, -50 MVAR leading

Individual Unit Auxiliary Load at Maximum Summer MW Output (MW/MVAR): ____

Individual Unit Auxiliary Load at Minimum Summer MW Output (MW/MVAR): _____

Individual Unit Auxiliary Load at Maximum Winter MW Output (MW/MVAR): ______

Individual Unit Auxiliary Load at Minimum Winter MW Output (MW/MVAR): ______

Station Service Load (MW/MVAR): __________ 70 MW spread evenly over the 2 units

* GSU losses are expected to be minimal.
** Your project's declared MW, as first submitted in Attachment N, and later confirmed or modified by the Impact Study Agreement, should be based on either the 92° F Ambient Air Temperature rating of the unit(s) or, if less, the declared Capacity rating of your project.

Unit Generator Dynamics Data

Queue Letter/Position/Unit ID: ________________________ M04 (Calvert Cliffs unit1)

MVA Base (upon which all reactances, resistance and inertia are calculated): _____ 1020

Nominal Power Factor: ____ 0.9

Terminal Voltage (kV): ____ 25

Unsaturated Reactances ***(on MVA Base)***

Direct Axis Synchronous Reactance, $X_{d(i)}$: ______________________________ 1.61

Direct Axis Transient Reactance, X'd(i): ______________________________ 0.355

Direct Axis Sub-transient Reactance, X"d(i): ___________________________ 0.280

Quadrature Axis Synchronous Reactance, Xq(i): _______________________ 1.51

Quadrature Axis Transient Reactance, X'q(i): _________________________ 0.557

Quadrature Axis Sub-transient Reactance, X"q(i): _____________________ 0.280

Stator Leakage Reactance, Xl: ______________________________________ 0.21

Negative Sequence Reactance, X2(i): ________________________________ 0.235

Zero Sequence Reactance, X0: _____________________________________ 0.190

Saturated Sub-transient Reactance, X"d(v) (on MVA Base): __________________ 0.235

Armature Resistance, Ra (on MVA Base): ______________________________________

Time Constants (seconds)

Direct Axis Transient Open Circuit, T'_{do}: _____________________________ 6.771

Direct Axis Sub-transient Open Circuit, T''_{do}:_ _________________________ 0.031

Quadrature Axis Transient Open Circuit, T'_{qo}:_ _________________________ 0.385

Quadrature Axis Sub-transient Open Circuit, T''_{qo}: ______________________ 0.053

Inertia, H (kW-sec/kVA, on KVA Base): ______________________________ 4.395

Speed Damping, D: ____ 0

Saturation Values at Per-Unit Voltage [S(1.0), S(1.2)]: ____________________ 0.1, 0.44

Units utilize a GENROU Generator model

Unit GSU Data

Queue Letter/Position/Unit ID:________________________ M04 (Calvert Cliffs unit1)

Generator Step-up Transformer MVA Base: ___Two 810 MVA TX connected in parallel

Generator Step-up Transformer Impedance (%, on transformer MVA Base): __20.55% (both)

Generator Step-up Transformer Rating (MVA):_____________________________810.0

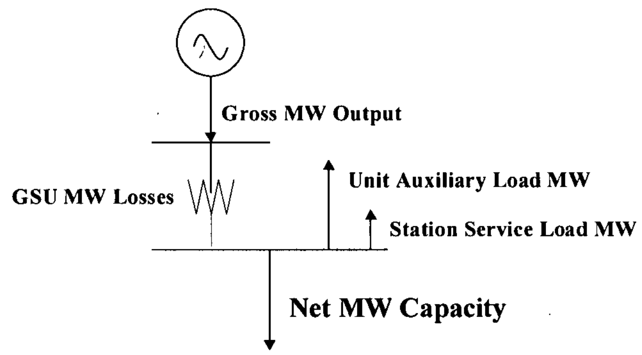
Generator Step-up Transformer Low-side Voltage (kV): _______________________25.0

Generator Step-up Transformer High-side Voltage (kV):______________________500.0

Generator Step-up Transformer Off-nominal Turns Ratio:_____________________1.05

Generator Step-up Transformer Number of Taps and Step Size: ___3 taps of 2.5 % above And 1 tap of 2.5% below

Unit Capability Data



Net MW Capacity = (Gross MW Output - GSU MW Losses* – Unit Auxiliary Load MW - Station Service Load MW)

Queue Letter/Position/Unit ID: ____________________ M04 (Calvert Cliff unit2)

Primary Fuel Type: ____________________ Nuclear

Maximum Summer (92° F ambient air temp.) Net MW Output**: ____________ 867

Maximum Summer (92° F ambient air temp.) Gross MW Output: ____________ 902

Minimum Summer (92° F ambient air temp.) Gross MW Output: ____________

Maximum Winter (30° F ambient air temp.) Gross MW Output: ____________

Minimum Winter (30° F ambient air temp.) Gross MW Output: ____________

Gross Reactive Power Capability at Maximum Gross MW Output – Please include Reactive Capability Curve (Leading and Lagging):350 MVAR lagging, -50 MVAR leading

Individual Unit Auxiliary Load at Maximum Summer MW Output (MW/MVAR): ____

Individual Unit Auxiliary Load at Minimum Summer MW Output (MW/MVAR): ____

Individual Unit Auxiliary Load at Maximum Winter MW Output (MW/MVAR): ____

Individual Unit Auxiliary Load at Minimum Winter MW Output (MW/MVAR): ____

Station Service Load (MW/MVAR): ________ 70 MW spread evenly over the 2 units

* GSU losses are expected to be minimal.
** Your project's declared MW, as first submitted in Attachment N, and later confirmed or modified by the Impact Study Agreement, should be based on either the 92° F Ambient Air Temperature rating of the unit(s) or, if less, the declared Capacity rating of your project.

Unit Generator Dynamics Data

Queue Letter/Position/Unit ID: ________________________ M04 (Calvert Cliff unit2)

MVA Base (upon which all reactances, resistance and inertia are calculated): _____ 1003

Nominal Power Factor: ____

Terminal Voltage (kV): ____22.0

Unsaturated Reactances ***(on MVA Base)***

Direct Axis Synchronous Reactance, $X_{d(i)}$: ____________________________1.599

Direct Axis Transient Reactance, X'd(i):______________________________0.442

Direct Axis Sub-transient Reactance, X"d(i): ________________________0.301

Quadrature Axis Synchronous Reactance, Xq(i): ______________________1.561

Quadrature Axis Transient Reactance, X'q(i):_________________________0.682

Quadrature Axis Sub-transient Reactance, X"q(i): ____________________0.301

Stator Leakage Reactance, Xl: ____________________________________0.2250

Negative Sequence Reactance, X2(i): __________________________________

Zero Sequence Reactance, X0: _______________________________________

Saturated Sub-transient Reactance, X"d(v) (on MVA Base):______________________

Armature Resistance, Ra (on MVA Base): ______________________________

Time Constants (seconds)

Direct Axis Transient Open Circuit, T'_{do}: ____________________________5.95

Direct Axis Sub-transient Open Circuit, T''_{do}:_ ________________________0.035

Quadrature Axis Transient Open Circuit, T'_{qo}:_ _________________________1.5

Quadrature Axis Sub-transient Open Circuit, T''_{qo}: ____________________0.07

Inertia, H (kW-sec/kVA, on KVA Base): ____________________________3.346

Speed Damping, D: ____ 0

Saturation Values at Per-Unit Voltage [S(1.0), S(1.2)]: _______________ 0.096, 0.3133

Units utilize a Genrou Generator model

Unit GSU Data

Queue Letter/Position/Unit ID:_________________________ M04 (Calvert Cliff unit2)

Generator Step-up Transformer MVA Base: ___Two 810 MVA TX connected in parallel

Generator Step-up Transformer Impedance (%, on transformer MVA Base):20.94% and 20.88%

Generator Step-up Transformer Rating (MVA):_____________________________810.0

Generator Step-up Transformer Low-side Voltage (kV): _______________________22.0

Generator Step-up Transformer High-side Voltage (kV):______________________500.0

Generator Step-up Transformer Off-nominal Turns Ratio:______________________1.05

Generator Step-up Transformer Number of Taps and Step Size: ___3 taps of 2.5 % above
And 1 tap of 2.5% below

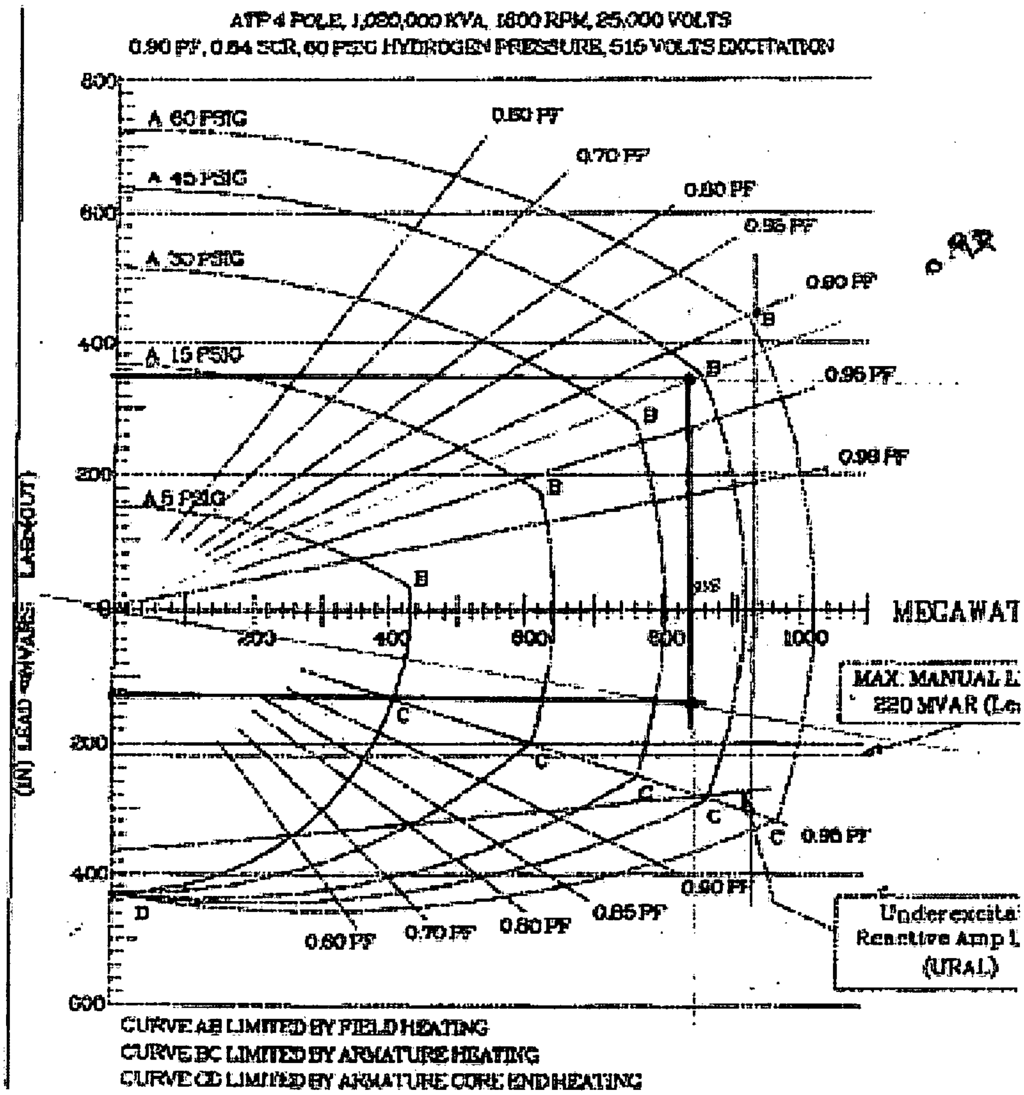
ATTACHMENT #2

(Unit #1 and #2 Capability Curves)

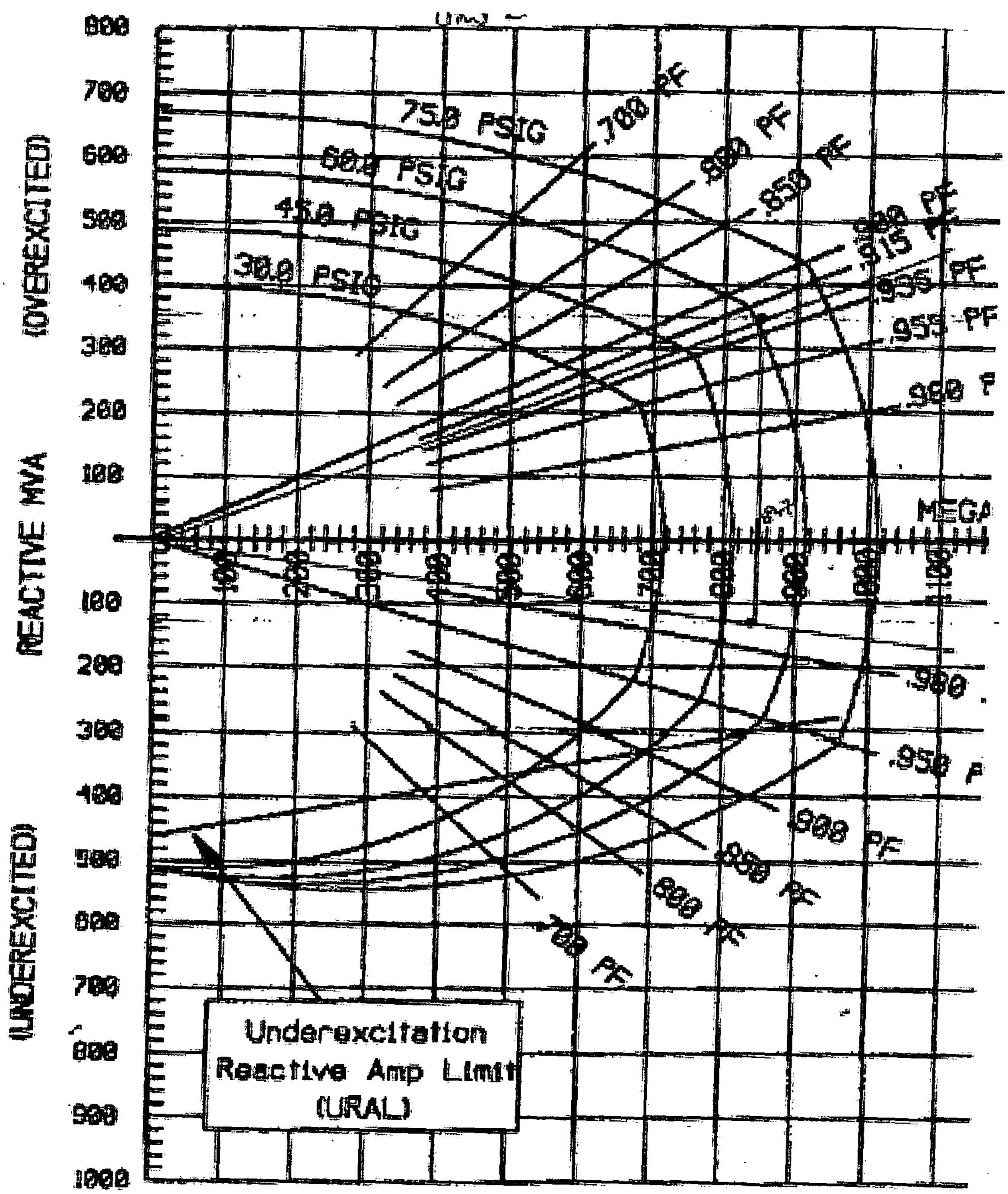
Unit #1

1. **<u>WHEN</u> the Voltage Regulator is in MANUAL,**
<u>THEN</u> the steady-state Reactive Load shall <u>NOT</u> exceed 220 MVAR (LI
[B0219]

Unit 1



Unit #2



REACTIVE MVA
(OVEREXCITED)
(UNDEREXCITED)
800
700
600
500
400
300
200
100
100
200
300
400
500
600
700
800
900
1000
100
200
300
400
500
600
700
800
900
1000
1100
MEGA
75.0 PSIG
60.0 PSIG
45.0 PSIG
30.0 PSIG
.700 PF
.800 PF
.850 PF
.900 PF
.915 PF
.956 PF
.955 PF
.980 P
.980
.950 P
.900 PF
.850 PF
.800 PF
.700 PF
Underexcitation
Reactive Amp Limit
(URAL)

ENCLOSURE (3)

PJM System Dynamics Working Group Procedure Manual, February 2006

Calvert Cliffs Nuclear Power Plant, Inc.
December 29, 2008

PJM

SYSTEM DYNAMICS WORKING GROUP

PROCEDURE MANUAL

February 2006

FOREWORD

This manual is a product of the PJM System Dynamics Working Group (SDWG). PJM footprint encompasses several NERC reliability regions consisting of many transmission owners. The manual contains the scope, study guidelines and procedures which define and support the activities of the SDWG. The procedural manual is intended for use by PJM and members of PJM for the purpose of creating and maintaining dynamics base cases and dynamics simulation details that are to be used to evaluate the dynamic performance of the systems in the PJM footprint.

PJM and most of the Regional member utilities use Power Technologies Inc. (PTI) Power System Simulator (PSS/E) software. Therefore, the various activities in the procedure manual incorporate PTI's procedures and nomenclature in describing these activities.

TABLE OF CONTENTS

I. INTRODUCTION

Dynamic Stability Analysis is performed by PJM as a part of the system impact study for proposed generation interconnection to the PJM system. PJM also conducts periodic appraisals of PJM system performance and dynamic assessment of the effects of system condition changes which are deemed to have a reasonable possibility of occurring during PJM system operation. PJM staff performs the bulk of the analysis by applying the criteria set by NERC, NERC reliability regions and also applicable transmission owners' criteria where the new projects are interconnected.

II. PURPOSE OF THE SDWG

PJM System Dynamics Working Group (SDWG) was created by PJM Planning Committee (PC) in January 2005 in order to develop and maintain an integrated system dynamics analysis procedure manual for PJM system. The manual is developed for the use of PJM and its members in planning and to evaluate operating conditions of the PJM bulk electric power systems.

III. PROCEDURES

Dynamics base cases

Base cases for stability analysis are created in a similar manner to that of the load flow base cases. However, additional information is necessary in order to simulate the combined dynamic responses of various system components across the transmission system. Included in this additional information are models for generators, excitation systems, power system stabilizers, governors, load models and various other equipment. A dynamic simulation links the system model or load flow information with the dynamic data or models to determine if the system and generators will remain stable for a steady-state and various disturbances.

The current RTEP summer peak case is used as a starting point to create new dynamics cases (light load and peak load) in the following year.

The following steps are observed in creating and updating the two dynamics cases.

1) Obtain and Review the Designated RTEP Power Flow Case
   The power flow case is reviewed with regards to its linkage to the dynamics database.

2) Correlate the Power Flow Data with the Dynamics Data

   Correlate the RTEP power flow data with the dynamic data to determine any missing dynamics data. Also determine if there is any data in the database for which there is no corresponding power flow data.

3) Review the Power Flow and the Dynamics Database for Questionable Data

   Review the RTEP power flow data and its dynamics data files such as DYRE, CONEC and CONET to identify questionable and bad data.

Testing and Initializing Dynamics Cases

The following steps are observed in creating dynamics simulation cases.

Perform Initialization Based on DYRE, CONEC, CONET and RAWD Files

Read the updated power flow data (RAWD or saved case) into the PSS/E power flow program. Solve the AC power flow case. After the AC solution, convert the generators and load using the CONG and CONL activities. Using activities FACT and TYSL, solve the converted power flow case. Save the converted case.

Using the PTI PSS/E dynamics simulation skeleton program, read in the solved converted power flow case. Perform activities FACT and TYSL.

Perform activity DYRE and read in the DYRE dynamics data file. Note and document any warning and error messages that are displayed. Create the CONEC and CONET files and compile command procedure before exiting the PSS/E dynamics simulation program. Resolve any problems identified by the activity DYRE

Add the user-written source codes to the respective CONEC and CONET files and execute the compile command procedure previously created. Create a snapshot to be used with the PSSDS executable. Execute CLOAD4 to link the files, thereby creating a PSSDS executable.

Using the user PSSDS executable created, read in the solved converted power flow case. Perform activities FACT and TYSL. Perform activity STRT. Note any states that are not initializing properly, i.e., any dynamic states whose derivatives are not zero, within the standard tolerance. Document and correct as needed these noninitializations of states. Repeat this procedure until all initialization problems have been corrected.

Once all the dynamic state initialization problems have been corrected, create a new snapshot, and using activity RUN execute the dynamic simulation for 20 seconds, unperturbed. Use PTI's PSAS to establish output channels for these simulations. Adjust the integration time step and/or correct data until the dynamic simulation (unperturbed) is judged to be steady-state stable.

The final, initialized set of power flows and the associated snap-shots, along with the compile file (DSUSR.dll file for the PC platform) and the GNET/CONL files are provided to the PJM members for their use.

Load Level

Each RTEP dynamic case is one of the following model types:

Summer Peak Load: the summer peak demand expected to be served

Light Load: 50% of the summer peak load. Pumped storage hydro units are modeled in the pumping mode.

Outside Equivalents

The regions adjacent to PJM are modeled in sufficient details using their models from the NERC power system dynamics database (SDDWG)

Dispatch

The assumptions used for generation dispatch can be critical to the results. It is generally accepted that units operating at their highest possible power output and generating as little reactive power as necessary to maintain voltages are likely to be less stable. Normally, the units in the vicinity of the project under study will be turned on to their maximum real power output with unity power factor at the high side of the GSU's. However, some Transmission Owners do not set the high side of GSU to unity power factor, instead adjust units VAR output to hold scheduled voltages.

Modeling Details

Where the GSU of a synchronous or induction generator or synchronous condenser is not modeled in the RTEP power flow case, the GSU shall be represented in the dynamic case. Station light and power Load is also required to be modeled explicitly. Currently a few units have their station light and power loads modeled in the RTEP cases.

Simulation Details

The Criteria for performing studies in the PJM system shall meet the requirements of the NERC Reliability Standards, NERC reliability region criteria, applicable transmission owner criteria and applicable specific generating plant criteria. The following factors need to be addressed in simulations;

a) Criteria Based Case lists:

1) Faults Types: Close-in three phase faults, close-in single line to ground faults with stuck breaker and close-in single line to ground faults with the communications failure cleared with zone2 time.

2) Clearing Times: All clearing times used are representative "worst case scenarios" for use as a screening tool for dynamic studies. Clearing times are provided by the Transmission owners to the PJM Relay Subcommittee (Appendix 4). Actual clearing times are used when stability problems are identified.

3) Reclosing: Only high speed reclosing is modeled if present.

b) Maintenance outages: All EHV line maintenance outages near a generating plant are evaluated for three-phase, normally cleared faults only. No breaker failure or 2nd zone test is applied.

c) Margins: With the machine modeled at net unity power factor at the high-side of the GSU, transient stability must be maintained when the following tests are applied:

- Add 0.25 cycles to the nominal primary clearing time for 3 phase, normally cleared faults.
- Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 0.5 cycles added to the nominal backup clearing time for stuck breaker.
- Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 1.25 cycles to the nominal Zone2 clearing time for failure of primary relaying.

PPL does not use fixed time margins. They increase study area generation MW output by 7% as a margin.

d) Monitoring requirements: Rotor angle, Real power output, EFD, speed and terminal voltage of units under study are monitored. Bus Voltages in the same area are also monitored.

e) Acceptable Voltage Dip: Following the disturbance, the voltages of the monitored buses maintain acceptable voltages within ±5% of the original precontingency voltages

f) Acceptable Damping: Following the disturbance, the oscillation of the monitored parameters display a positive damping of oscillation. The positive damping can be observed by drawing an envelope connecting each succeeding peak of the oscillation of the monitored element. This envelope will demonstrate a steady decay within the appropriate test period (normally 10 seconds). Positive damping demonstrates an acceptable response by the system, and no further analysis is required.

g) with/Without PSS: If a PSS is going to be out of service for more than 24 hours, it is evaluated for any possible unit output restriction unless it has been studied for that condition in previous simulation testing.

Load Models

Static loads are typically modeled in accordance with each Area's or Region's practice as follows

	Real Power		Reactive Power	
Region	Constant Current %	Constant Impedance %	Constant Current %	Constant Impedance %
MAAC	100	0	0	100
ECAR	100	0	0	100
MAIN	100	0	0	100
SERC *	100	0	0	100

* Applicable to DVP, only PJM Member Company in SERC. Rest to be from the SDDWG dynamics cases

APPENDIX 1

NERC Criteria

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	 Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c]	 No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. *Any two circuits of a multiple circuit towerline* [f]	 Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c]	 No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. *Transmission Circuit* 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

MAAC Criteria

Reliability Standards

The bulk transmission system shall be developed:

- with flexibility in switching arrangements, voltage control, and other control measures, to ensure reliable system operation under a wide range of operating conditions,
- so that with all transmission facilities in service and normal scheduled generator maintenance, the loadings of all system components shall be within normal ratings, stability limits and normal voltage limits,
- so that it can be operated to meet the following unscheduled contingencies, at all forecasted load levels and firm transfers, without instability, cascading or widespread interruption of load.

A. The loss of any single transmission line, generating unit, transformer, bus section, circuit breaker, Phase Angle Regulators or single pole of a bipolar DC line in addition to normal scheduled outages of bulk electric supply system facilities without exceeding the applicable emergency rating of any facility or applicable voltage criteria. This shall include the loss of any single facility due to a three-phase fault with normal clearing time and the loss of any single facility with no fault. After the outage, the system must be capable of readjustment so that all equipment (on the MAAC and neighboring systems) will be loaded within normal ratings and within normal voltage criteria.

B. After occurrence of a contingency outage and the readjustment of the system specified in II.A, the subsequent contingency outage of any remaining generator, line, Phase Angle Regulator or transformer without exceeding the short-time emergency rating of any facility and within emergency voltage criteria. After this outage, the system must be capable of readjustment so that all remaining equipment will be loaded within applicable emergency ratings and voltage criteria for the probable duration of the outage.

C. The loss of any two circuits of a multiple circuit tower line which is one mile or greater in length, bipolar DC line, a faulted circuit breaker or the combination of facilities resulting from a single phase to ground fault coupled with a stuck breaker or other cause for delayed clearing in addition to normal scheduled generator outages without exceeding the applicable emergency rating of any facility or applicable voltage criteria. After the outage, the system must be capable of readjustment so that all equipment will be loaded within applicable emergency ratings for the probable duration of the outage.

In determining the bulk transmission requirements, recognition shall be given to the occurrence of similar contingencies in neighboring systems and their effect on the MAAC system. Interruption of interruptible load in the area of study may be used for readjustment of the system. Stability includes both voltage and angular stability in the transient time frame and beyond. Contingencies may be simulated at any voltage level but only the performance of the Bulk Electric Supply System of MAAC will be evaluated.

ECAR Criteria

Reliability Standards

1. Individual systems shall be planned such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected demands and provide contracted firm transmission services.

2. Individual systems shall be planned such that the network can be operated to supply projected demands and contracted firm transmission services with any single outage of a transmission line, transformer, special control device or generator due either to a forced outage or the failure of a primary protective device or special protective scheme.
The transmission systems shall also be capable of accommodating bulk facility maintenance outages scheduled prior to such contingencies.

3. Individual systems shall be planned such that the network can be operated to supply projected demands and contracted firm transmission services with contingencies such as the loss of a bus section, breaker failure, double circuit tower outage or the delayed clearing of a single line to ground fault of a generator, bus section, or transmission element. Such contingencies can result in the outage of more than one element or facility. The controlled interruption of demand, the planned removal of generators, or the curtailment of contracted firm power transfers is permitted.

4. The transmission systems shall also be capable of accommodating facility maintenance outages, scheduled prior to such contingencies.

5. Individual systems shall be planned such that Cascading shall not result from the condition of a single outage of a transmission line, transformer, special control device or generator due either to a forced outage or the failure of a primary protective device or special protective scheme, followed by a second single outage. Before or after the second contingency, the controlled interruption of demand, the planned removal of generators, manual intervention or the curtailment of contracted firm power is permitted.

SERC Criteria

The SERC Region does not have its own separate Reliability Criteria as such and has adopted the NERC Reliability Standards as its basis for planning the bulk electric power system. However, SERC has prepared several Supplements where NERC requires Regions to establish certain requiremnets for their members and/or need clarification to be compliant with the NERC requirements.

SERC recognizes that its individual members can have their own internal criteria that is more stringent than the NERC Standards or the SERC Supplaments. However, they may not be less restrictive than the NERC criteria.

Dominion Virginia Power (DVP) is the only SERC member at present that has joined PJM for operational control of its transmission system. The details of stability study criteria for DVP is listed in Appendix 2.

MAIN Criteria

MAIN GUIDE NO. 2
TRANSMISSION PLANNING PRINCIPLES AND GUIDES

Reliability Standards

1. Electric systems should be planned such that under credible contingencies at projected customer demand levels and anticipated electricity transfers, system voltages and facility loading remain within acceptable limits.

2. Credible, less probable multi-element contingencies at projected customer demand levels and anticipated electricity transfers should be evaluated for risks, consequences, and corrective actions to avoid cascading outages or voltage collapse resulting in uncontrolled interruptions to customer electric supply over a wide area.

3. System normal and single contingency conditions at projected customer demand levels and higher than anticipated electricity transfers should be evaluated for risks, consequences, and corrective actions to avoid cascading outages or voltage collapse resulting in uncontrolled interruptions to customer electric supply over a wide area.

V. APPENDIX 2

BGE Criteria

Dynamic Analysis

III.D.1 Introduction

Dynamic stability describes the ability of the power system to remain synchronized following a disturbance. Dynamic stability analysis includes transient or first swing stability analysis and up to 10 minutes after any disturbance. Analyzing the system for dynamic stability is crucial to the security of the system, as certain contingencies on the system could cause the system to become unstable.

Because the growth in system loads tend to make the system more stable by adding additional damping, dynamic stability analysis is performed when system changes occur that could affect dynamic performance. The need for this analysis is initiated via various sources including but not limited to the following:

- Primary and backup relay scheme changes
- The addition, removal, or re-rating of generation on the system
- Generation control system changes
- Large network impedance changes
- Abnormal system configuration

The base case for stability analysis is created in a similar manner to that of the load flow and short circuit base cases. However, additional information is necessary in order to simulate the combined dynamic responses of various equipment across the transmission system. Included in this additional information are models for generators, excitation systems, power system stabilizers, governors, and various other equipment. A dynamic simulation links the system model or load flow information with the dynamic data or models to determine if the system or generators within the system will remain stable for various disturbances.

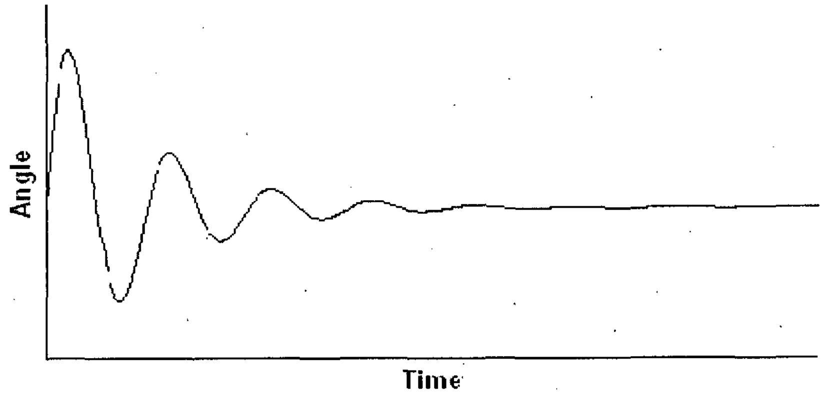
Loads are modeled as constant power in loadflow analysis; however, during stability analysis, loads should be modeled as constant current for the real portion (MW) and constant impedance for the reactive portion (MVAR) unless a representation is known that more specifically applies to the system studied.

All base cases are developed by PJM or MAAC and submitted to BGE upon request. BGE modifies the case as required to suit the specific study. The worst case load level (light, intermediate, or peak) should be utilized to study each scenario except when studies are initiated by bulk power operations with specific system conditions that need to be modeled.

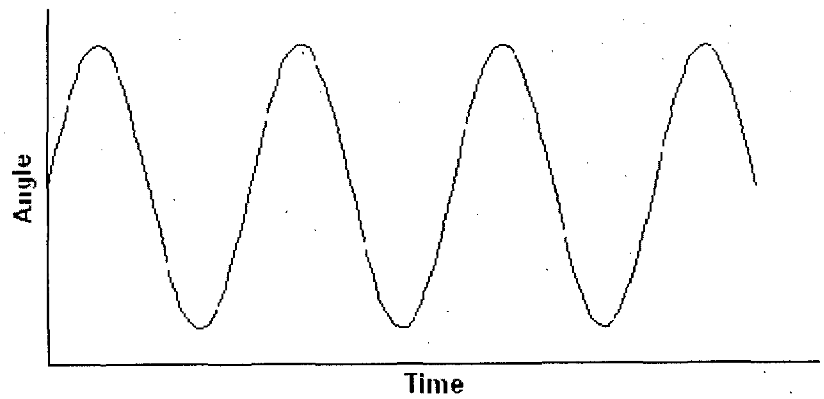
The power system's response to a disturbance is simulated to determine whether or not the system remains stable. In most cases, the output of the simulation is analyzed in graphical form, either creating a power vs. angle curve or plotting system variables (angle, voltage, power, frequency, etc.) with respect to time.

The plot below illustrates a system disturbance that remains stable. In this simulation, a fault occurred at time 0+ and the magnitude of the oscillations reduced in magnitude as time increased.

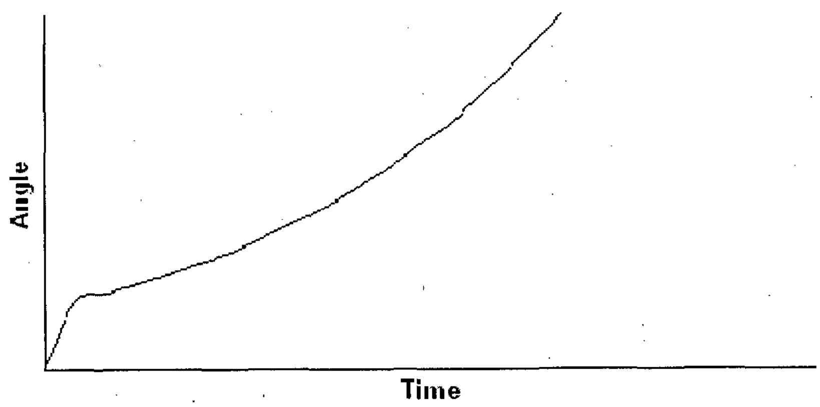
Plot 1 System Remaining Stable After Disturbance



Two examples of unstable systems can be found below. Plot 2 illustrates a system disturbance that causes sustained oscillations and Plot 3 illustrates a system disturbance that causes dynamic instability.



Plot 2 System Experiencing Sustained Oscillations



Plot 3 System Experiencing Dynamic Instability

III.D.2 Disturbances

Per PJM/MAAC criteria, the stability of BGE's and neighboring transmission systems must be sustained without loss of load for all contingencies as described in section III.D.1.a including:

- Three-phase fault with normal clearing
- Single phase-to-ground fault with a stuck breaker or any other cause for delayed clearing
- The loss of any single facility with no fault

For BGE, the system should remain stable given the following disturbances:

- Three-phase fault at a point 80% of the circuit impedance away from the station under study with zone two clearing
- Failure of a generator
- Failure or all generation from one station
- Opening or closing of a transmission facility
- Loss of a large block of load
- Faulted circuit breaker

For all of the disturbances above, the system must maintain angle stability. In cases where the system is unstable, the system should be enhanced to improve stability as set forth in section III.D.4.

III.D.3 Performing the Analysis

BGE performs dynamic stability analysis utilizing the PSS/e Power System Simulation software. Base case load flow and dynamics data are obtained from either PJM or MAAC and will include the BGE system in as much detail as possible with the neighboring systems as modeled by PJM or MAAC. When performing the analysis the most up-to-date information should be used. This would include any recent enhancements to system models, generation models, or operating times.

For all contingencies involving faults, the fault clearing times are of the utmost importance. The amount of time it takes for a fault to clear has a direct impact on the stability of the system.

When performing dynamic stability analysis actual operating times should be obtained from the Design and Engineering Analysis section of the System Protection & Control Master Section whenever possible. These times include zone one and zone two clearing times, backup clearing times, reclosing times, and auto-transfer times. The clearing times include the total relay trip times plus the longest probable breaker interrupting times. Whereas in short circuit analysis we use the quickest possible total interrupting times to simulate worst case scenarios, for stability, we assume the longest possible total interrupting times to simulate worst case scenarios.

Often, transmission operations may request a stability analysis be performed for any contingency given the system in an abnormal configuration. When these requests are made, great effort should be taken to modify the base case so that it is as similar as possible to the system configuration under study. The load level, generation dispatch, and voltage control mechanisms should be reviewed to create a study case as close as possible to what the system is experiencing.

III.D.4 Possible Solutions

There are several ways to enhance system stability in the event that unstable conditions are identified. Some are listed below.

- The addition of power system stabilizers
- Shorten fault clearing times (primary or backup)
- Generation runback or trip schemes

- Limitation of generation output
- Addition of transmission lines
- Addition of transmission series capacitors
- Addition of transmission shunt capacitors
- Addition of dynamic reactive devices
- Schemes for the removal or transferal of load

An analysis of the system's response to a disturbance that causes instability will provide an indication as to what system enhancements can be employed to attain stability. An economic analysis must be performed to determine the best solution.

As a delivery company, BGE does not own generators to which it can make enhancements. BGE can only change the characteristics of the transmission system to make the system stable. PJM may direct those that control the generating stations to make changes to their units for stability problems and BGE may provide input to that process if the generating unit impacts BGE's facilities.

DVP Criteria

There are many different variables that affect the results of a stability study. These factors include:

- pre-fault and post-fault system configuration
- system load level and load characteristics
- generation dispatch patterns and unit dynamic characteristics
- type and locations of system disturbances
- total fault clearing time(s)
- the amount of flow interrupted as a result of switching out a faulted element
- level of detail and accuracy of available models/data
- proximity to other generating units

Many of these factors change in the operating arena on a continuous basis. Every effort should be made to evaluate the most severe, yet credible/probable combinations of line/faults/equipment failures.

General Requirements (for New and Existing Installations)

The criteria for performing stability studies near generating stations on Dominion Virginia Power (DVP) system should meet, at a minimum, the requirements of the NERC Reliability Standards (the Standards). Furthermore, some additional criteria have been established (see Additional Requirements below) as a prudent utility practice to maintain and enhance stability. These additional measures should provide some margin to the minimum requirements of the Standards and should protect the system for any unpredicted deterioration in system operating conditions and/or data inaccuracies.

For breaker failure backup clearing, it will be assumed that only one pole is "stuck" where three separate mechanisms (independent poles) are available (e.g. all 500 kV breakers on DVP system).

The results of stability studies are generally valid for about 15 to 20 seconds following a disturbance. Therefore, disturbance simulations will be carried out to 15 to 20 seconds, in general, and no attempt will be made to simulate any time re-closure after 15-second time period. The transformer taps are frozen at the pre-disturbance level throughout the simulations.

Additional Requirements

A. For new Installations

Stability must be maintained for the breaker failure backup clearing following a three-phase fault (not just for a single-phase-to-ground fault as required by the Standards) near generating stations with all system components in-service as planned prior to the contingency. The severity of the fault to be applied may be reduced to a two-phase-to-ground fault provided that out-of-step protection is applied to the generating unit(s). The generation tripped due to an out-of-step condition should be generally limited to an amount equivalent to the largest generator on the system.

Stability must also be maintained for the delayed-clearing of a three-phase fault due to a primary protection system failure with all system components in-service as planned prior to the contingency. The fault shall be placed at the end of the first zone coverage resulting in a second zone trip. It is not necessary to test for this condition where dual primary relays are installed.

B. For Existing Installations

Stability must be maintained for the breaker failure backup clearing following a two-phase-to-ground fault (not just for a single-phase-to-ground fault as required by the Standards) near generating stations with all system components in-service as planned prior to the contingency.

Stability must also be maintained for the delayed-clearing of a two-phase-to-ground fault due to a primary protection system failure with all system components in-service as planned prior to the contingency. The fault shall be placed at the end of the first zone coverage resulting in a second zone trip. It is not necessary to test for this condition where dual primary relays are installed.

Special Considerations

Some of the items in Table I of the NERC Reliability Standards may not be very clear. The DVP's interpretation is that, in general, engineering judgement must be applied in such cases. For example, at what system load levels the studies need to be performed? It is easy to say at "all load levels" but it is not practical. A generator angular stability is generally more critical at lighter load levels than at peak load. Generally, DVP performs stability studies at 60 to 70 percent load levels since the system is exposed to this load level for longer period of time during a given year. Also, the plant under study is to be fully dispatched and nearby other units may need to be dispatched being ON or OFF depending on system topology. Some locations may need to be studied with different base case scenarios with different generation dispatches to assess the proper impact on stability.

For a transmission component being out in the base case (i.e. forced or maintenance outages), this operating condition is generally for a short period of time. The decision to trip the unit for the next contingency, should it occur, or to reduce the output on a temporary basis would depend on the location and importance of the plant. The decision to install high-speed unit trips or special stability relays or to accept restriction on unit output will be made on a case by case basis. Furthermore, there may be situations where the cost is excessive, or it is not practical to engineer a project to alleviate an unstable condition(s). In such cases, a decision may be made to live with the situation as long as the probability of such occurrences is rare, and the resulting unstable condition is confined to local area only (i.e. without the danger of cascading).

AEP TRANSIENT STABILITY DISTURBANCE TESTING CRITERIA

PREFAULT CONDITION	765 KV PLANTS	345 KV PLANTS	138 KV PLANTS
All Transmission Facilities in Service	1A Permanent single line-to-ground (SLG) fault with 1φ breaker failure. Fault cleared by backup breakers.	2A Permanent SLG fault with 1φ breaker failure. Fault cleared by backup breakers.	3A Permanent SLG fault with 3φ breaker failure. Fault cleared by backup breakers.
	1B Permanent SLG fault cleared by primary breakers. 3φ fault developed following HSR. Fault cleared by primary breakers.	2B Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by backup breakers.	3B Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by backup breakers.
	1C 3φ line opening without fault.	2C 3φ line opening without fault.	3C 3φ line opening without fault.
One Transmission Facility Out of Service	1D Permanent SLG fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	2D Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	3D Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.
	1E 3φ line opening without fault.	2E 3φ line opening without fault.	3E 3φ line opening without fault.
Two Transmission Facilities Out of Service	1F Temporary SLG fault with successful HSR, if applicable.	2F Temporary 3φ fault with successful HSR, if applicable.	3F Temporary 3φ fault with successful HSR, if applicable.
	1G 3φ line opening without fault.	2G 3φ line opening without fault.	3G 3φ line opening without fault.

PPL Criteria

With regard to PPL EU's stability analysis methods, in general, PPL follow MAAC criteria. PPL EU's interpretation of the criteria requires that system stability must be maintained, without significant loss of generation, for the following types of fault conditions occurring at the most critical location at ANY (peak, intermediate or light) load level:

1) Permanent three-phase fault cleared by normal primary relay action, including reclosing, if applicable.
2) Permanent phase to ground fault and the failure of a protective device to operate properly causing a stuck circuit breaker, delayed clearing or other events having similar probability of occurrence.
3) Permanent three-phase fault at a point 80% of the line impedance away from the generating facility under consideration with delayed (Zone 2) clearing times, including reclosing, if applicable.

In addition, PPL EU considers less probable contingencies to determine the severity of the consequences. These less probable events are:

a) Permanent three phase fault involving both circuits of a double circuit line with normal clearing and reclosing sequences, if applicable (tower failure scenario).
b) Permanent three-phase fault with stuck breaker or other cause of delayed clearing.
c) Permanent three phase fault on one line with an overtrip of another unfaulted line. Both the overtrip and clearing of the faulted line occur in normal primary clearing time. Reclosing sequences, if applicable, should be included.

If the tests normally performed show that the system will not remain stable, or the consequences of the less probable contingencies are severe, additional studies are performed to determine methods to eliminate the stability concern.

It should also be noted that in order to provide and maintain reasonable supply to PPL customers and other facilities, PPL EU assumes a transient synchronous stability safety margin of 7%. This implies that the net summer certified capacity of the generator being studied in the PPL EU territory is increased by 7% to account for periods of abnormal or unusual system operation.

ComEd Criteria

ComEd Transmission Planning Security Criteria

PHI Criteria

Dynamic Stability analysis is applied when we are studying either transient or voltage stability cases. It addresses the transmission system dynamic behavior for certain disturbances and determines if adjustments or enhancements are needed for reliable system operation.

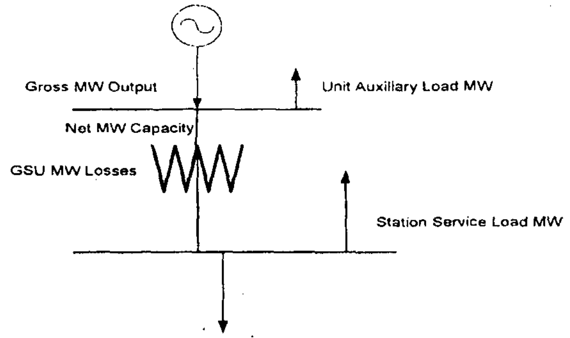
For Transient Stability analysis, we study the system at light load. Transient stability refers to a situation where following a disturbance (e.g., single-line to ground or three-phase fault), electromechanical oscillations occur between generators. These oscillations may cause generators to become unstable and trip offline at some point after the disturbance. The time frame of this instability will be in the order of 0 to 10 seconds which will capture only generator inertial and excitation dynamics. We will apply the rotor angle maximum swing criteria (<100 degrees) and use bus voltage & frequency deviations.

For Voltage Stability analysis, we study the system at peak load. Voltage stability accounts for the longer-term effects, which are generally times greater than 30 seconds. This type of analysis will involve the loss of more controls and equipment reaching their limits, which will eventually lead to a progressive voltage decrease followed by collapse. This includes the effects of prime mover control, LTC, and excitation limiters.

PHI, at a minimum, applies the same criteria set forth by PJM and MAAC regarding stability analysis. We use the same power flow cases and supporting files. We evaluate three-phase (3PH) faults, single-line-to-ground (SLG) faults, and single-line-to-ground (SLG) faults with stuck breaker. We also follow their same criteria for load modeling (100% constant current for real power and 100% constant impedance for reactive power).

Appendix 3 Generator data request form

Unit Capability Data



Net MW Capacity = (Gross MW Output – Unit Auxiliary Load MW)

Queue Letter/Position/Unit ID: ______________________________

Primary Fuel Type: ______________________________

Maximum Summer (92° F ambient air temp.) Net MW Output**: ____________

Maximum Summer (92° F ambient air temp.) Gross MW Output: ____________

Minimum Summer (92° F ambient air temp.) Gross MW Output: ____________

Maximum Winter (30° F ambient air temp.) Gross MW Output: ____________

Minimum Winter (30° F ambient air temp.) Gross MW Output: ____________

Gross Reactive Power Capability at Maximum Gross MW Output – Please include Reactive Capability Curve (Leading and Lagging): ____________

Individual Unit Auxiliary Load at Maximum Summer MW Output (MW/MVAR): _____

Individual Unit Auxiliary Load at Minimum Summer MW Output (MW/MVAR): _____

Individual Unit Auxiliary Load at Maximum Winter MW Output (MW/MVAR): _____

Individual Unit Auxiliary Load at Minimum Winter MW Output (MW/MVAR): _____

Station Service Load (MW/MVAR): ______________________________

* GSU losses are expected to be minimal.

** Your project's declared MW, as first submitted in Attachment N, and later confirmed or modified by the Impact Study Agreement, should be based on either the 92° F Ambient Air Temperature rating of the unit(s) or, if less, the declared Capacity rating of your project.

Unit Generator Dynamics Data

Queue Letter/Position/Unit ID: ____________________

MVA Base (upon which all reactances, resistance and inertia are calculated): __________

Nominal Power Factor: ____________________

Terminal Voltage (kV): ____________________

Unsaturated Reactances (on MVA Base)

Direct Axis Synchronous Reactance, $X_{d(i)}$: ____________________

Direct Axis Transient Reactance, X'd(i): ____________________

Direct Axis Sub-transient Reactance, X"d(i): ____________________

Quadrature Axis Synchronous Reactance, Xq(i): ____________________

Quadrature Axis Transient Reactance, X'q(i): ____________________

Quadrature Axis Sub-transient Reactance, X"q(i): ____________________

Stator Leakage Reactance, Xl: ____________________

Negative Sequence Reactance, X2(i): ____________________

Zero Sequence Reactance, X0: ____________________

Saturated Sub-transient Reactance, X"d(v) (on MVA Base): ____________________

Armature Resistance, Ra (on MVA Base): ____________________

Time Constants (seconds)

Direct Axis Transient Open Circuit, T'_{do}: ____________________

Direct Axis Sub-transient Open Circuit, T''_{do}: ____________________

Quadrature Axis Transient Open Circuit, T'_{qo}: ____________________

Quadrature Axis Sub-transient Open Circuit, T''_{qo}: ____________________

Inertia, H (kW-sec/kVA, on KVA Base): ____________________

Speed Damping, D: ____________________

Saturation Values at Per-Unit Voltage [S(1.0), S(1.2)]: ____________________

Units utilize a Generator model

Unit GSU Data

Queue Letter/Position/Unit ID:____________________

Generator Step-up Transformer MVA Base: ____________________

Generator Step-up Transformer Impedance (R+jX, or %, on transformer MVA Base):________

Generator Step-up Transformer Reactance-to-Resistance Ration (X/R): ____________

Generator Step-up Transformer Rating (MVA): ____________________

Generator Step-up Transformer Low-side Voltage (kV): ________________

Generator Step-up Transformer High-side Voltage (kV): ________________

Generator Step-up Transformer Off-nominal Turns Ratio: ________________

Generator Step-up Transformer Number of Taps and Step Size:____________

PJM Relay Subcommittee
Survey of Fault Clearing Times

Voltage Level	Case	Fault Condition	Representative worst case total clearing times (cycles) AE	DPL	BGE	GPU	PPL	PECo	PEPCO	PSEG	AP	VP*	ComEd	AEP
765 kV	1	Three phase or SLG fault w/ Normal Clearing - All relaying in service											3.0-3.5	3.0 - 4.0
	2	SLG fault w/ Delayed Clearing - Due to Failure of primary relaying											3.0-3.5	3.0 - 4.0
	3	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Generating Stations)											na	14
	4	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Non-Generating Stations)											11-12	14
500 kV	1	*Three phase or SLG fault w/ Normal Clearing -* All relaying in service	-	3.5 - 4.0	3.5 - 4.5	3.5 - 4.0	3.5	3.5 - 4.0	3.7-4.2	4	4	3.5 - 4.5	na	3.5 - 4.0
	2	SLG fault w/ Delayed Clearing - Due to Failure of primary relaying	-	3.5 - 4.0	3.5 - 4.5	24.5 - 25.5	3.5	3.5 - 4.0	3.7-4.2	4	21	3.5 - 4.5	na	3.5 - 4.0
	3	*SLG fault w/Delayed Clearing -* Due to Stuck Breaker (at Generating Stations)	-	-	12.0 - 13.0	12.0 - 13.0	9	10-12.5	11.7-13.6	12	na	8.75 - 13.5**	na	14
	4	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Non-Generating Stations)	-	10.0 - 12.5	12.0 - 13.0	12.0 - 13.0	12	12.5	11.0-12.1	16	12	8.75 - 13.5**	na	14
345 kV	1	Three phase or SLG fault w/ Normal Clearing - All relaying in service				3.5 - 4.0							3.0-4.5	3.5 - 4.0
	2	SLG fault w/ Delayed Clearing - Due to Failure of primary relaying				25.5 - 26.5							3.0-4.5	3.5 - 4.0
	3	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Generating Stations)				13.0 - 14.0							7.5-13	15
	4	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Non-Generating Stations)				13.0 - 14.0							11-13	15
230 kV	1	Three phase or SLG fault w/ Normal Clearing - All relaying in service	4.0 - 5.0	4.0 - 5.0	4.5	4.0 - 5.0	4.0 - 8.0	4.0 - 5.0	4.2-4.7	5	5	4.5 - 5.5	na	4.5 - 5.0
	2	SLG fault w/ Delayed Clearing - Due to Failure of primary relaying	34.0 - 35.0	24.0 - 25.0	34.0	34	35	28-30	4.2-4.7	30	30	30.0 - 33.0	na	4.5 - 5.0
	3	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Generating Stations)	16.5 - 17.5	15.0 - 16.0	14.0 - 15.0	14.0 - 15.0	9.0 - 10.0	11.0-15.0	11.6-12.1	17	na	11.5 - 14.0	na	16
	4	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Non-Generating Stations)	16.5 - 17.5	15.0 - 16.0	14.0 - 15.0	14.0 - 16.0	12.0 - 17.0	11.0-15.0	11.6-12.1	17	15	11.5 - 26.0	na	16
115 kV & 138 kV	1	Three phase or SLG fault w/ Normal Clearing - All relaying in service	5.0 - 7.0	5.0 - 7.0	4.5	5.0 - 7.0	5.0 - 8.0	6.0-7.0	4.4-6.4	6	7	4.5 - 5.5	3.5-6.0	4.5 - 5.0
	2	SLG fault w/ Delayed Clearing - Due to Failure of primary relaying	35.0 - 37.0	35.0 - 37.0	34.0	36	30.0 - 60.0	30-32	4.4-6.4	30	36	33.0 - 41.0	20-27	33 - 63
	3	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Generating Stations)	17.5 - 19.5	17.5 - 19.5	14.0 - 15.0	17.0 - 20.0	30.0 - 60.0	17	20.6-22.0	18	na	11.5 - 26.0	13-15	18
	4	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Non-Generating Stations)	17.5 - 19.5	17.5 - 19.5	14.0 - 15.0	19.0 - 20.0	30.0 - 60.0	17	20.6-22.0	18	20	11.5 - 26.0	13-20	18
69 kV	1	Three phase or SLG fault w/ Normal Clearing - All relaying in service	5.0 - 10.0	5.0 - 10.0	-	5.0 - 10.0	7.0 - 12.0	9.0-11.0	6.4-6.7	6		4.5 - 10.5	3.0-9.0	33 - 63
	2	SLG fault w/ Delayed Clearing - Due to Failure of primary relaying	35.0 - 70.0	35.0 - 70.0	-	36.0 - 40.0	30.0 - 60.0	31-35	6.4-6.7	30		33.0 - 44.0	20-27	33 - 93
	3	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Generating Stations)	20.5 - 25.5	17.5 - 22.5	-	17.0 - 23.0	30.0 - 60 0	18-20	22.6-24.0	na		11.5 - 29.0	13-20	na
	4	SLG fault w/Delayed Clearing - Due to Stuck Breaker (at Non-Generating Stations)	20.5 - 25.5	17.5 - 22.5	-	19.0 - 23.0	30.0 - 60.0	18-20	22.6-24.0	19		11.5 - 29.0	13-20	33 - 93

SUBJECT: Calvert Cliffs Transmission Grid Interface Specification

REFERENCES: 1. Calvert Cliffs UFSAR
2. Calvert Cliffs Tech Specs
3. Docketed Correspondence

1. 500 kV Switchyard is designed to function reliability under all conditions of power plant operation. It will furnish startup power to the power plant, and reliably function and isolate trouble in the power system grid under normal and abnormal conditions.

2. Load flow and stability studies indicate that the tripping of one or both fully loaded Calvert Cliffs generating units would not impair the ability of the system to supply plant service. These studies were made at projected peak load conditions and also at minimum load conditions when the two Calvert Cliffs units were supplying the entire Baltimore System. In addition, some major transmission circuits were assumed to be out of service at the time.

3. The spinning reserve policy of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, of which BGE is a member, is to maintain enough reserve capacity synchronized to the system to cover the largest single contingency in the PJM.

4. Transient stability under fault conditions in the switchyard has been verified by digital computer study which included the interconnected systems and analyzed for various contingencies, including the failure of a 500 kV breaker to trip under a fault condition.

5. The required switchyard operating voltage range to prevent operation of the vital 4kV bus degraded voltage relays is 500 to 550kV with an allowable contingency situation of 475kV (5% drop). If either of the plant service transformers are out of service, the required switchyard voltage range becomes 520 to 550kV. Operation of the vital 4kV degraded voltage relaying separates the vital 4kV system from the offsite sources and places them on the emergency diesel generators. This relaying operates if 4kV voltage drops to less than 90% of nominal for more than 101 seconds, 75% of nominal for more than 8 seconds or on loss of voltage after 2 seconds.

6. Restoration of offsite power after a station blackout is assumed to take not less than 12 hrs to accomplish.

7. The minimum requirement for frequency for offsite power for the Calvert Cliffs units is greater than 57.5Hz. If the frequency of the offsite power drops to 57.5Hz or less for 6 cycles, both Calvert Cliffs turbine/generators will trip on under-frequency. Buy procedure, both Calvert Cliffs units are operated at not less than 58.5 Hz. Also, the Calvert Cliffs units do not regulate frequency when paralleled to the grid.

REFERENCES: 1. Calvert Cliffs UFSAR
2. Calvert Cliffs Tech Specs
3. Docketed Correspondence

8. Tech Spec requirements for offsite sources:
The offsite power supply shall consist of two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power Distribution System. Calvert Cliffs offsite supplies consist of 3 500kV transmission lines (each of which can handle the full output of both Calvert Cliffs Units simultaneously) and a single 69/13.8 kV line (which is designed to supply only the necessary power to maintain both Calvert Cliffs units in a safe shutdown condition simultaneously). Any two of the four aforementioned sources will satisfy the offsite source requirements in the Tech Specs.

Exelon and AmerGen Nuclear Generating Stations

The following is a list of stability cases referenced in our plant UFSAR's that are beyond the required MAAC stability criteria.

Limerick:

1) The Limerick Units 1 & 2 generators are to be stable for the following cases:

   a) 3 phase close in fault on any single 500 kV or 230 kV line, where the most critical Limerick circuit breaker fails to open and the fault is cleared at Limerick by backup protective equipment (8 cycles).
   b) 3 phase high side or low side faults on the 4A/B transformer, where the most critical Limerick circuit breaker fails to open and the fault is cleared at Limerick by backup protective equipment (8 cycles).
   c) Simultaneous 3 phase close in faults on the 5030 and 5031 lines cleared by primary protection equipment (3.5 cycles).

2) The transmission system is to remain stable for the following three cases with either one or both Limerick units in service:

   a) Loss of Peach Bottom Units 2 & 3
   b) Loss of the largest single load, North Wales substation
   c) Simultaneous 3 phase faults on 5030, 5031, 220-62, and 130-30 lines in the vicinity of Perkiomen substation with normal clearing.

Peach Bottom:

No cases beyond the required MAAC stability criteria.

TMI:

No cases beyond the required MAAC stability criteria

Oyster Creek:

1) There will be no Oyster Creek generating unit transient instability, transmission system transient instability, transmission line overloads or cascading outages as a result of a 3 phase fault with backup delayed clearing (i.e. stuck breaker) of any one of the two 230 kV lines emanating from Oyster Creek.
2) There will be no Oyster Creek generating unit transient instability, transmission system transient instability, transmission line overloads or cascading outages as a result of a 3 phase fault with primary relay clearing involving any of the 34.5 kV lines emanating from Oyster Creek.
   Note: This is considered required by the MAAC criteria since a fault on the 34.5 kV system must not create bulk transmission system overloads, instability or cascading outages, however it is identified here for emphasis because of Oyster Creek's unique interconnections to the 34.5 kV system.

3) The simultaneous loss of the Oyster Creek generating unit and the largest generating unit in New Jersey (Salem Unit 2) will not result in transmission system transient instability, transmission line overloads, cascading outages or intolerable voltage conditions.

PPL Susquehanna Stability Analysis Criteria

The PPL 230kv and 500kV Transmission System is planned in accordance with Mid-Atlantic Area Council (MAAC) Reliability Principles and Standards. In general, the stability requirements are that the system shall be maintained without loss of load during and after the following types of contingencies based on the latest load forecast prepared annually by the PJM Load Analysis Subcommittee.

- Single contingency outage conditions (MAAC reliability criteria section IIA)
- Double circuit tower line outage or single stuck circuit breaker conditions (MAAC reliability criteria section IIC)
- Three phase faults with normal clearing time (MAAC reliability criteria section IV)
- Single line to ground faults with a stuck breaker or other cause for delayed clearing (MAAC reliability criteria section IV)

The MAAC reliability criteria also require an evaluation of the ability of the bulk power system to withstand abnormal system disturbances (MMAC reliability criteria section V). The MAAC reliability criteria does not require that the bulk power system be planned and constructed to withstand these abnormal disturbances due to their low probability of occurrence. However, it is PPL Electric Utilities position to maintain these cases stable for PPL Susquehanna. These abnormal system disturbances are analyzed not on the basis of their likelihood of occurrence but rather as a practical means to study the system for its ability to withstand disturbances beyond those that can be reasonably expected.

A total of six (6) contingencies identified in the FSAR Table 8.2-1 are required by MAAC standards. Seventeen (17) other contingencies are not required by MAAC standards but analyzed to assure a high level of transmission system reliability. FSAR table 8.2-1 is attached with the list of stability cases performed for PPL Susquehanna LLC.

TABLE 8.2-1

SUSQUEHANNA UNIT #1 & #2
STABILITY CASE LIST
(SUMMER LIGHT LOAD CONDITIONS)

CASE	DESCRIPTION	RESULT 1998 UPDATE
Fault Tests Required to be Stable (8.2.1.5.C)		
R-1	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line. Fault cleared in primary clearing time.	Stable
R-5	Phase-ground fault at Susquehanna 500 kV on Sunbury 500 kV line with Sunbury South 500 kV circuit breaker stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.	Stable
R-6	3 phase fault at Susquehanna 230 kV on the Susquehanna 500/230 kV transformer. Fault cleared in primary clearing time.	Stable
R-7	3 phase fault at Montour 230 kV on Susquehanna 230 kV line. Fault cleared in normal primary clearing time.	Stable
R-13	Phase-ground fault at Susquehanna 500 kV on Susquehanna-Wescosville-Alburtis 500 kV line with Wescosville South 500 kV circuit breaker stuck. Clear remote terminal in primary time. Delayed clearing at Susquehanna.	Stable
R-18	3 phase fault at Susquehanna 230 kV on Harwood (E. Palmerton) Double Circuit. Fault cleared in primary clearing time.	Stable

TABLE 8.2-1

SUSQUEHANNA UNIT #1 & #2
STABILITY CASE LIST
(SUMMER LIGHT LOAD CONDITIONS)

CASE	DESCRIPTION	RESULT 1998 UPDATE
Fault Tests Not Required to be Stable (8.2.1.5.C)		
N-2	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line with one breaker pole stuck at Sunbury. Clear Susquehanna in primary time. Delayed clearing at remote terminal.	Stable
N-3	3 phase fault at Susquehanna 500 kV on the Susquehanna-Wescosville-Alburtis 500 kV line with one Susquehanna 500/230 kV transformer breaker pole stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.	Stable
N-4	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line with one Susquehanna 500/230 kV transformer breaker pole stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.	Stable
N-8	3 phase fault at Susquehanna 230 kV on Montour line with stuck west bus breaker. Clear remote terminal in primary time, clear Susquehanna with delay (lose Stanton-Susquehanna #2 230 kV line).	Stable
N-9	3 phase fault at Susquehanna 230 kV on Jenkins line with stuck east bus breaker. Primary clearing at remote terminal. Delayed clearing at Susquehanna.	Stable
N-10	3 phase fault at Susquehanna 230 kV on the 500/230 kV transformer with stuck west bus breaker. Primary clearing at remote terminal (Susquehanna 500 kV Switchyard). Delayed clearing at Susquehanna 230 (lose Stanton-Susquehanna #2 230 Kv line).	Stable
N-11	3 phase fault at Susquehanna 230 kV on Harwood line with stuck tie breaker pole. Clear two poles in primary time. Clear stuck pole in delayed clearing time (lose Sunbury-Susquehanna 230 kV line).	Stable

TABLE 8.2-1

SUSQUEHANNA UNIT #1 & #2
STABILITY CASE LIST
(SUMMER LIGHT LOAD CONDITIONS)

CASE	DESCRIPTION	RESULT 1998 UPDATE
N-12	3 phase fault at Susquehanna 230 kV on E. Palmerton line with one pole stuck on west bus breaker. Clear two poles in primary time. Clear stuck pole in delayed clearing time (lose Stanton-Susquehanna #2 230 kV line).	Stable
N-14	Susquehanna-Wescosville- Alburtis 500 kV and Susquehanna-Harwood (E. Palmerton) Double Circuit 230 kV crossing failure (3 phase fault on all circuits). Automatically trip Susquehanna Unit #1. Clear Susquehanna-Wescosville-Alburtis 500 kV line in primary time. Clear Susquehanna-Harwood and Susquehanna-E. Palmerton 230 kV lines in primary time.	Stable
N-15	3 phase fault near E. Palmerton on all lines in E. Palmerton-Harwood R/W corridor. Clear Susquehanna-Wescosville-Alburtis 500 kV line in primary time. Primary clearing of E. Palmerton-Susquehanna and Harwood-Siegfried 230 kV lines.	Stable
N-16	3 phase fault near Susquehanna on both lines in Sunbury-Susquehanna R/W corridor. Clear Sunbury-Susquehanna #2 500 kV line in primary time. Primary clearing of Sunbury-Susquehanna #1 230 kV line.	Stable
N-17	3 phase fault near Susquehanna 500 kV at Sunbury 230 kV line crossing. Trip Susquehanna-Wescosville-Alburtis 500 kV, Sunbury-Susquehanna #2 500 kV, and Unit #2 in primary time. Trip Sunbury-Susquehanna #1 230 kV in primary clearing time.	Stable
N-19	3 phase fault at Columbia-Frackville 230 kV line crossing. Trip Sunbury-Susquehanna #2 500 kV line in primary time. Trip Columbia-Frackville and Sunbury-Susquehanna #1 230 kV lines in primary time.	Stable
N-20	3 phase fault on 230 kV side of Unit #1 main transformer. Trip Unit #1 main transformer. Trip Unit #1 and overtrip Unit #2 in primary time (loss of entire station).	Stable
N-21	3 phase fault at Susquehanna 230 kV on Unit #1 generator leads with a stuck west bus breaker. Trip Unit #1 and Stanton #2 line.	Stable

TABLE 8.2-1

SUSQUEHANNA UNIT #1 & #2
STABILITY CASE LIST
(SUMMER LIGHT LOAD CONDITIONS)

CASE	DESCRIPTION	RESULT 1998 UPDATE
N-23	Sudden loss of all lines from Susquehanna 230 kV Switchyard	Stable
N-24	3 Phase fault on Susquehanna-Jenkins 230 kV line 80% towards Jenkins with pilot relaying out. Fault cleared in Zone 2 (backup) time at Susquehanna and Zone 1 time at Jenkins.	Stable

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Revised: 2.7.2006

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ENCLOSURE (4)

PJM Manual 14B: PJM Region Transmission Planning Process, Section 2,

Revision 12, Effective Date: 08/08/2008

Calvert Cliffs Nuclear Power Plant, Inc.
December 29, 2008

pjm

Working to Perfect the Flow of Energy

PJM Manual 14B:

PJM Region Transmission Planning Process

Revision: 12

Effective Date: 08/08/2008

Prepared by
Planning Division
Transmission Planning Department

PJM Manual 14B:

PJM Region Transmission Planning Process

Table of Contents

Section 2: Regional Transmission Expansion Plan Process

In this section you will find an overview of the PJM Region transmission planning process, covering the following areas:

- Components of PJM's 15-Year planning
- The need and drivers for a regional transmission expansion plan
- Reliability planning overview
- Specific components of reliability planning and the Stakeholder process
- Interconnection request drivers of RTEP
- Cost responsibility for reliability related upgrades
- Market efficiency planning review
- Specific components of market efficiency planning and the Stakeholder process.
- Operational performance driven planning
- Specific components of operational performance driven planning

Transmission Planning = Reliability Planning + Market Efficiency

Effective with the 2006 RTEP, PJM, after stakeholder review and input, expanded its RTEP Process to extend the horizon for consideration of expansion or enhancement projects to fifteen years. This enables planning to anticipate longer lead time transmission needs on a more timely basis.

Fundamentally, the Baseline reliability analysis underlies all planning analysis and recommendations. On this foundation, PJM's annual 15-year planning review now yields a regional plan that encompasses the following:

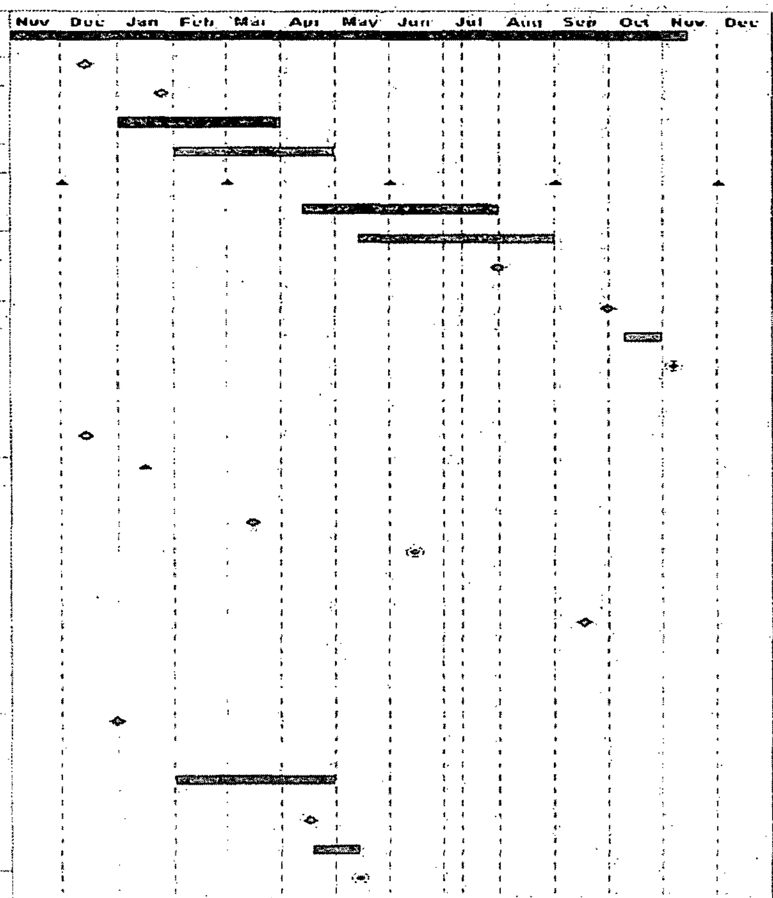
1. Baseline reliability upgrades, discussed in this Section 2;
2. Generation and transmission interconnection upgrades, discussed in Attachment C and Manual 14A.
3. Market efficiency driven upgrades, discussed in this Section 2.
4. Operational performance issue driven upgrades, discussed in this Section 2.

Exhibit 1 shows the annual cycle of the 15-year RTEP process. This cycle integrates reliability and market efficiency analysis with information transparency, stakeholder input and review and PJM Board of Manager approvals. This Cycle is discussed in detail in this and related manuals and attachments. Activities shown on this diagram and their timing are an idealized view that will be responsive to the RTEP and Stakeholder needs and thus may vary accordingly.

Exhibit 1: PJM Annual RTEP Planning Cycle for 15-Year Plan

This timeline represents the idealized RTEP process. At the beginning of each RTEP cycle, PJM will provide specific timeline information for the upcoming study cycle.

ID	Task Name
1	**RELIABILITY PLANNING**
2	Subregional RTEP Committee initial assumptions meeting
3	TEAC review/input: realibility assumptions
4	PJM analysis: near-term reliability
5	PJM-stakeholder communication & reviews: ongoing
11	[Quarterly Queue Impact Study Start Dates]
12	PJM analysis: long-term thermal & reactive reliability
13	PJM-stakeholder communication & reviews: ongoing
14	Subregional RTEP Committee review/input: violations & upgrades
15	TEAC review/input: reliability violations & upgrades
16	Post TEAC meeting comment period
17	BOM review & approval: RTEP reliability plan
18	**MARKET EFFICIENCY PLANNING (current RTEP year) (monthly posting of historical congestion drivers)**
19	Subregional RTEP Committee initial assumptions meeting
20	[PJM [illegible]]
21	PJM: Market efficiency assumptions development
22	TEAC review/input: market efficiency assumptions
23	BOM review and approval: market efficiency assumptions
24	PJM analysis: historical congestion, projection of congestion & conceptual solutions
25	TEAC or Subregional RTEP Committee review/input: congestion drivers and conceptual solutons
26	PJM analysis: acceleration of reliability upgrades
27	**Market Efficiency Planning (previous RTEP year)**
28	Deadline: Stakeholder Market solutions
29	PJM analysis: new market efficiency solutions
30	TEAC or Subregional RTEP Committee review/input: market efficiency solutions
31	TEAC review/input: market efficiency solutions and analyses
32	Post TEAC meeting comment period
33	BOM review and approval: RTEP market efficiency plan



The RTEP Process Drivers

The continuing evolution and growth of PJM's robust and competitive regional markets rests on a foundation of bulk power system reliability, ensuring PJM's ongoing ability to meet control area load-serving obligations. It also includes a commitment to enhance the robustness and competitiveness of Energy and Capacity markets by incorporating analysis and development of market efficiency projects. Schedule 6 of the PJM Operating Agreement describes the PJM RTEP process, governing the means by which PJM coordinates the preparation of a plan for the enhancement and expansion of the Transmission Facilities – on a reliable and environmentally sensitive basis and in full consideration of available economic and market efficiency factors and alternatives - in order to meet the demands for firm transmission service in the PJM region. PJM's FERC-approved RTEP process preserves this foundation through independent analysis and recommendation, supported by broad stakeholder input and approval by an independent RTO Board in order to produce a single RTEP.

The PJM Region transmission planning process is driven by a number of planning perspectives and inputs, including the following:

- ReliabilityFirst Regional Reliability Corporation[2] (RFC) Reliability Assessment – forward-looking assessments performed to assure compliance with NERC and applicable regional reliability corporation (ReliabilityFirst or SERC Reliability Corporation) reliability standards, as appropriate.
- SERC Reliability Corporation (SERC) Reliability Assessment
- PJM Annual Report on Operations – an assessment of the previous year's operational performance to assure that any bulk power system operational conditions which have emerged, e.g., congestion, are adequately considered going forward.
- PJM Load Serving Entity (LSE) capacity plans
- Generator and Transmission Interconnection Requests – submitted by the developers of new generating sources and new Merchant Transmission Facilities, these requests seek interconnection in the PJM Region (or seek needed enhancements as the result of increases in existing generating resources.)
- Transmission Owner and other stakeholder transmission development plans
- Interregional transmission development plans – the transmission expansion plans of those power systems adjoining PJM, and in some cases, beyond.
- Long-term Firm Transmission Service Requests
- Activities under the PJM committee structure especially, the Planning Committee (PC), the Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee, and local groups facilitated by PJM within

[2] Reliability*First*, a new regional reliability corporation under the North American Electric Reliability Corporation (NERC), replaced three existing PJM-related reliability councils (ECAR, MAAC and MAIN) on January 1, 2006.

the TEAC established processes (see section 1 "TEAC, Subregional RTEP Committee, and related planning activities".)

- PJM Development of Economic Transmission Enhancements based on Economic and Market Efficiency factors
- Operational performance assessments and reviews such as the aging Infrastructure Initiative – a Probabilistic Risk Assessment of equipment that poses significant risk to the Transmission System.

The cumulative effect of these drivers is analyzed through the PJM Region transmission planning process to develop a single RTEP which recommends specific transmission facility enhancements and expansion on a reliable and environmentally sensitive basis and in full consideration of economic and market efficiency analyses. See Attachment B for details of the RTEP – Scope and Procedure.

> **NOTE:** The most recent version of the PJM RTEP is available PJM Web site at http://www.pjm.com/planning/reg-trans-exp-plan.html.

These analyses are conducted on a continual basis, reflecting specific new customer needs as they are introduced, but also readjusting as the needs of Transmission Customers and Developers change. One such RTEP baseline regional plan will be developed and approved each year

> **NOTE:**
>
> Generation withdrawals have the potential to impact study results for any generation or merchant transmission project that doesn't have an executed ISA.
>
> Generation retirements will not affect the study results for any generation or merchant transmission project that has received an Impact Study Report (i.e. No Retool – the generator retirements are applied at the next baseline update.)
>
> Generation retirements included in interconnection project studies will be those announced as of the date a project enters the interconnection queue.

In this way, the plan continually represents a reliable means to meet the power system requirements of the various Transmission Customers and Interconnection Customers in a fully integrated fashion, at the same time preserving the rights of all parties with respect to the Transmission System. The assurance of a reliable Transmission System and the protection of the Transmission Customer/Developer rights with respect to that system coupled with the timely provision of information to stakeholders are the foundation principles of the PJM transmission planning process.

The PJM Region transmission planning process also establishes the cost responsibility for the following types of facility enhancements as defined in the PJM Tariff: .

- Attachment Facilities
- Direct Assignment Facilities
- Network Upgrades (Direct and Non-direct)
- Local Upgrades

- Merchant Network Upgrades

Each RTEP encompasses a range of proposed power system enhancements: circuit breaker replacements to accommodate increased current interrupting duty cycles; new capacitors to increase reactive power support; new lines, line reconductoring and new transformers to accommodate increased power flows; and, other circuit reconfigurations to accommodate power system changes as revealed by the drivers discussed above.

Requests for interconnection of new generators or transmission facilities, while not the sole drivers of the PJM Region transmission planning process, are a key component of the RTEP. Analyzing these requests has required adoption of an approach that establishes baseline system improvements driven by known inputs, followed by separate queue-defined, cluster-based impact study analyses. Overall, PJM's RTEP process – under a FERC-approved RTO model – encompasses independent analysis, recommendation and approval to ensure that facility enhancements and cost responsibilities can be identified in a fair and non-discriminatory manner, free of any market sector's influence. All PJM market participants can be assured that the proposed RTEP was created on a level playing field.

RTEP Reliability Planning

Establishing a Baseline

In order to establish a reference point for the annual development of the RTEP reliability analyses a 'baseline' analysis of system adequacy and security is necessary. The purpose of this analysis is threefold:

- To identify areas where the system, as planned, is not in compliance with applicable NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards including equipment replacement and/or upgrade requirements under PJM's Aging Infrastructure Initiative. The baseline system is analyzed using the same criteria and analysis methods that are used for assessing the impact of proposed new interconnection projects. This ensures that the need for system enhancements due to baseline system requirements and those enhancements due to new projects are determined in a consistent and equitable manner.
- To develop and recommend facility enhancement plans, including cost estimates and estimated in-service dates, to bring those areas into compliance.
- To establish the baseline facilities and costs for system reliability. This forms the baseline for determining facilities and expansion costs for interconnections to the Transmission System that cause the need for facilities beyond those required for system reliability.

The system as planned to accommodate forecast demand, committed resources, and commitments for firm transmission service for a specified time frame is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements, PJM Reliability Standards and PJM design standards. Areas not in compliance with the standards are identified and enhancement plans to achieve compliance are developed.

The 'baseline' analysis and the resulting expansion plans serve as the base system for conducting Feasibility Studies for all proposed generation and/or merchant transmission facility interconnection projects and subsequent System Impact Studies.

Baseline Reliability Analysis

PJM's most fundamental responsibility is to plan and operate a safe and reliable Transmission System that serves all long term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM RTEP reliability planning. Reliability planning is a series of detailed analyses that ensure reliability under the most stringent of the applicable NERC, PJM or local criteria. To accomplish this each year, the RTEP cycle extends and updates the transmission expansion plan with a 15 year review. This cycle entails several steps. The following sections describe each step's assumptions, process and criteria. Attachments A through G of this manual add essential details of various aspects of the reliability planning process.

Reliability planning involves a near-term and a longer term review. The near term analysis is applicable for the current year through the current year plus 5. The longer term view is applicable for the current year plus 6 through plus 15. Each review entails multiple analysis steps subject to the specific criteria that depend on the specific facilities and the type of analysis being performed.

The analysis is initiated in December prior to each annual cycle and concludes with review by the TEAC and approval by the PJM Board about October (TEAC and the PJM Board are appraised regularly throughout the process and partial reviews and approvals of the plan may occur throughout the year.) The TEAC, Subregional RTEP and PJM Planning Committee roles in the development of the reliability portion of the RTEP are described in Schedule 6 of the PJM Operating Agreement.

Near-Term Reliability Review

The near-term reliability review (current year plus 5) provides reinforcement for criteria violations that are revealed by applicable contingency analysis. System conditions revealed as near violations will be monitored and remedied as needed in the following year near-term analysis. Violations that occur in many deliverability areas or severe violations in any one area will be referred to the long term analysis for added study of possible more robust system enhancement. PJM annually conducts this detailed review of the current year plus 5. Each year of the period through the current year plus 4 ("in-close" years) has been the subject of previous years' detailed analyses. In addition, for each of these "in-close" years, PJM updates and issues addendum to address changes as necessary throughout the year. For example planned generation modifications or changes in transmission topology can trigger restudy and the issuance of a baseline addendum. This is referred to as a "retool" study. (For example generators that drop from the Q's cause restudy and an addendum to be issued for affected baseline analyses.) Also each year during the establishment of the assumptions for the new annual baseline analysis, current updated views of load, transmission topology, installed generation, and generation and transmission maintenance are assessed for the "in-close" range of years to validate the continued applicability of each of the "in-close" baseline analyses and resulting upgrades (including any addendum.) Adjustments in the "in-close" analyses are performed as deemed necessary by PJM. PJM, therefore, annually verifies the continued need for or modification of past recommended upgrades through its retool studies, reassessment of current conditions and any needed adjustments to analyses. All criteria thermal and voltage violations resulting from the near term analyses are produced using solved AC power flow solutions. Initial massive contingency screening may use DC power flow solution techniques.

There are seven steps in an annual near-term reliability review. They are:

- Develop a Reference System Power Flow Case
- Baseline Thermal
- Baseline Voltage
- Load Deliverability - Thermal
- Load Deliverability - Voltage
- Generation Deliverability - Thermal
- Baseline Stability

These reliability related steps are followed by a scenario analysis that ensures the robustness of the plan by looking at impacts of variations in key parameters selected by PJM. Each of these steps are described in more detail in the following material

Reference System Power Flow Case

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability analysis. Each case is developed from the most recent set of Eastern Reliability Assessment Group system models. PJM transmission planning revises this model as needed to incorporate all of the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, and firm transactions. These assumptions will be provided to and reviewed by the Subregional RTEP Committee. The subregional modeling review and modeling assumptions meeting provides the opportunity for stakeholders to review and provide input to the development of the reference power system models used to perform the reliability analyses.

The results of any locational capacity market auction(s) will be used to help determine the amount and location of generation or demand side resources to be included in the reliability modeling. Generation or demand side resources that are cleared in any locational capacity market auction will be included in the reliability modeling, and generation or demand side resources that either do not bid or do not clear in any locational capacity market auction will not be included in the reliability modeling. All such modeling described here will comport with the capacity construct provisions approved by the FERC.

Subsequent to the subregional stakeholder modeling reviews facilitated by PJM, PJM will develop the final set of reliability assumptions to be presented to TEAC for review and comment, after which PJM will finalize the reliability review reference power flow. This model is expected to be available in early January of each year to interested stakeholders, subject to applicable confidentiality and CEII requirements, to facilitate their review of the results of the reliability modeling analyses.

Baseline Thermal Analysis

Baseline thermal analysis is a thorough analysis of the reference power flow to ensure thermal adequacy based on normal (applicable to system normal conditions prior to contingencies) and emergency (applicable after the occurrence of a contingency) ratings specific to the Transmission Owner facilities being examined. It is based on a 50/50 load forecast from the latest available PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load.) It encompasses an exhaustive analysis of all NERC category A, B and C events and the most critical common mode outages. Final results are supported with AC power flow solutions.

For normal conditions, all facilities shall be loaded within their normal ratings. After each single contingency, all control equipment is allowed to adjust. After the first contingency of a multiple-contingency event (NERC category C.3, also referred to as an "N-1-1" event,) all system adjustments are made to achieve a new steady state power flow, including redispatch in preparation for the next contingency. Subsequent to redispatch all facilities must be within normal ratings. After the second contingency of the pair the technique for single contingencies is followed except that phase shifters are locked and do not adjust to hold flow. All violations of emergency ratings are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Baseline Voltage Analysis

Baseline voltage analysis parallels the thermal analysis. It uses the same power flow and examines all the same NERC category A and B events. Baseline voltage analysis does not examine category C or common mode outages. Also, voltage criteria are examined for compliance. PJM examines system performance for both a voltage drop criteria and an absolute voltage criteria. The voltage drop is calculated as the decrease in bus voltage from the initial steady state power flow to the post-contingency power flow. The post-contingency power flow is solved with generators holding a local generator bus voltage to a pre-contingency level consistent with specific Transmission Owner specifications. In most instances this is the pre-contingency generator bus voltage. Additionally, all phase shifters, transformer taps, switched shunts, and DC lines are locked for the post-contingency solution. SVC's are allowed to regulate.

The absolute voltage criteria is examined for the same contingency set by allowing transformer taps, switched shunts and SVC's to regulate, locking phase shifters and allowing generators to hold steady state voltage criteria (generally an agreed upon voltage on the high voltage bus at the generator location.)

In all instances, specific Transmission Owner voltage criteria are observed. All violations are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Load Deliverability Analysis

The load deliverability tests are a unique set of analyses designed to ensure that the Transmission System provides a comparable transmission function throughout the system. These tests ensure that the Transmission System is adequate to deliver each load area's requirements from the aggregate of system generation. The tests develop an "expected value" of loading after testing an extensive array of probabilistic dispatches to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The Transmission System reliability criterion used is 1 event of failure in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.

Each load areas' deliverability target transfer level to achieve the transmission reliability criterion is separately developed using a probabilistic modeling of the load and generation system. The load deliverability tests described here measure the design transfer level supported by the Transmission System for comparison to the target transfer level. Transmission upgrades are specified by PJM to achieve the target transfer level as necessary. Details of the load deliverability procedure can be found in Attachment C.

Thermal

This test examines the deliverability under the stressed conditions of a 90/10 summer load forecast. That is, a forecast that only has a 10% chance of being exceeded. The transfer limit to the load is determined for system normal and all single contingencies (NERC category A and B criteria) under ten thousand load study area dispatches with calculated probabilities of occurrence. The dispatches are developed randomly based on the availability data for each generating unit. This results in an expected value of system transfer capability that is compared to the target level to determine system adequacy. As with all thermal transmission tests applied by PJM the applicable Transmission Owner normal and emergency ratings are applied. The steady state and single contingency power flows are solved consistent with the similar solutions described for the baseline thermal analyses.

Voltage

This testing procedure is similar to the thermal load deliverability test except that voltage criteria are evaluated and that a deterministic dispatch procedure is used to increase study area imports. The voltage tests and criteria are the same as those performed for the baseline voltage analyses.

Generation Deliverability Analysis

The generator deliverability test for the reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the Transmission System is capable of delivering the aggregate system generating capacity at peak load with all firm transmission uses modeled. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified capacity resources in each "area". Areas, as referred to in the generation deliverability test, are unique to each study and depend on the electrical system characteristics that may limit transfer of capacity resources. For generator deliverability areas are defined with respect to each transmission element that may limit transfer of the aggregate of certified installed generating capacity. The cluster of generators with significant impacts on the potentially limiting element is the "area" for that element. The starting point power flow is the same power flow case set up for the baseline analysis. Thus the same baseline load and ratings criteria apply. As already mentioned the same contingencies used for load deliverability apply and the same single contingency power flow solution techniques also apply. Details of the generation deliverability procedure can be found in Attachment C.

One additional step is applied after generation deliverability is ensured consistent with the load deliverability tests. The additional step is required by system reliability criteria that call for adequate and secure transmission during certain NERC category C common mode outages. The procedure mirrors the generator deliverability procedure with somewhat lower deliverability requirements consistent with the increased severity of the contingencies.

The details of the generator deliverability procedure including methods of creating the study dispatch can be found in Attachment C.

Baseline Stability Analysis

PJM ensures generator and system stability during its interconnection studies for each new generator. In addition, PJM annually performs stability analysis for approximately one third of the existing generators on the system. Analysis is performed on the RTEP baseline power flow. These analyses ensure the system is transiently stable and that all system oscillations display positive damping. Generator stability is performed for critical system conditions, which includes light load and three phase faults with normal clearing plus single line to ground faults with delayed clearing. Also, specific Transmission owner designated faults are examined for plants on their respective systems.

{PJM IS CURRENTLY EVALUATING STABILITY ANALYSIS NEEDS RELATED TO RFC CRITERIA. ANY REVISIONS OR ADDITIONS TO RTEP STABILITY ASSESSMENTS WILL BE INCLUDED HERE AS THAT REVIEW PROGRESSES AND WILL BE PRESENTED THROUGH THE APPROPRIATE PJM MANUAL REVIEW PROCESS.}

Finally, PJM will initiate special stability studies as the need arises. The impetus for such special studies commonly includes but is not limited to conditions arising from operational performance reviews or major equipment outages.

Long Term Reliability Review

The PJM RTEP reliability review process examines the longer term planning horizon using a current year plus 15 power flow model and a current year plus 10 power flow model. Assumptions and model development regarding this longer term view will be presented and reviewed and stakeholder input will be considered in the same process used for the near-term review. The longer term view of system reliability is subject to increased uncertainty due to the increased likelihood of changes in the analysis as time progresses. The purpose of the long term review is to anticipate system trends which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation during the near term horizon in anticipation of potential violations in the longer term. System issues uncovered that are amenable to shorter lead time remedies will be addressed as they enter into the near-term horizon.

<u>Current Year Plus 15 Analysis</u>

The Longer term reliability review involving single and multiple contingency analyses is conducted to detect system conditions which may need a solution with a lead-time to operation exceeding five years. Two processes will be used as indicators to determine the need for contingency analysis in the longer term horizon. The first is a review of the near-term results to detect violations that occur for multiple deliverability areas or multiple or severe violations clustered in a one area of the system. This review may suggest larger projects to collectively address groups of violations. The second is a thermal analysis including double circuit tower outages at voltages exceeding 100 kV performed on the current year plus fifteen system. All of the current year plus fifteen results produced will be reviewed to determine if any issues may require longer lead time solutions. If so such solutions will be determined and considered for inclusion in RTEP.

This evaluation of the need for longer lead time solutions considers that the NERC category C results may employ load shedding and/or curtailment of firm transactions to ease potential violations. Also this review considers that the current year plus fifteen planning horizon exceeds the required NERC planning horizon. The main effect of this extension to 15 years is to examine a load level that is significantly higher than the base forecast year-ten planning load level. This year fifteen analysis, therefore, captures the equivalent (in a 10-year horizon) of a higher load forecast plus weather sensitivity. To the extent that this long term reliability thermal review indicates marginal system conditions that may require a longer lead time solution, PJM will under take additional longer term analyses as may be needed.

The long term deliverability analyses follow a similar pattern to the near-term load and generation deliverability analyses. The long term, however, relies solely on linear DC analysis whereas all near term violations result from analysis solutions that rely on the full AC power flow. The load deliverability case is set up for a 90/10 load level and the generation deliverability case is set up for a 50/50 load level. Generation dispatches are determined consistent with the methods for the near term analyses. The analysis for the longer term horizon evaluates all NERC category A and B single contingencies against the same normal and emergency thermal ratings criteria used for the near term (subject to any upgrades that may be applicable for the longer term.)

Reactive Analysis

In addition, the longer term review includes a current year plus 10 reactive analysis. This focuses on contingencies involving facilities above 200 kV in areas where the preceding year-15 analysis uncovered thermal violations. Areas experiencing thermal violations that also show earlier reactive deficiencies will be reviewed for possible acceleration of any longer lead time thermal solutions that were suggested by the year-15 analysis. This analysis, as necessary from year to year, will also consider long-term upgrade sensitivity to key variables such as load power factor delivered from the Transmission System or heavy transfers. If uncovered violations are insufficient to justify acceleration of upgrades and are all amenable to shorter lead-time upgrades, then the violations will continue to be monitored in future RTEP analyses.

Stakeholder review of and input to Reliability Planning

RTEP reliability planning, through the operation of the TEAC and Subregional RTEP Committees, provides interested parties with the opportunity to review and provide meaningful and timely input to all phases of the reliability planning analyses. This section extends the Section 1 discussion of the TEAC and Subregional RTEP Committee process specifically as it relates to reliability planning. Exhibit 1 shows the workflow and timing for the reliability planning process steps. PJM anticipates at least two Subregional RTEP Committee reliability reviews. The initial subregional meeting will present and address reliability study assumptions and parameters. The second meeting will provide the opportunity for stakeholder comment and input on criteria violations and presentations of alternative remedies to identified violations. Between the two meetings PJM will provide feedback on interim study progress sufficient to enable stakeholder preparation for the second set of subregional meetings. Additional subregional meetings will be facilitated as

PJM determines is necessary for adequate input and review. The relative timing of the TEAC and subregional activities are illustrated in Exhibit 1.

Subregional RTEP Committee initial assumptions meeting

This meeting is expected to occur in ***December*** of each year in preparation for the upcoming annual RTEP review. Prior to the meeting PJM will post its anticipated inputs and assumptions to enable stakeholder review and preparation for the meeting. At the meeting PJM will present the assumptions for discussion and input by all interested parties. Subsequent to this meeting stakeholders will have additional opportunity to provide input to PJM in preparation for the next TEAC meeting, at which PJM will present the final reliability assumptions for TEAC review. Although the initial Subregional assumptions meeting will discuss anticipated assumptions for both the reliability and market efficiency phase of the RTEP, The final TEAC review of each will likely occur at separate TEAC meetings (see also the market efficiency discussion following.) The TEAC endorsement of final RTEP reliability assumptions is expected to occur in early ***January***.

PJM development of criteria violations and stakeholder participation

After the TEAC endorsement of PJM's RTEP analysis assumptions, PJM will finalize its reference system power flow which is the starting point of its series of reliability analyses. This power flow is available to stakeholders subject to applicable confidentiality and CEII requirements. PJM will perform its series of detailed RTEP reliability analyses encompassing the 15-year planning horizon. Details of the methods and procedures for the reliability analyses can be found elsewhere in this Manual 14B and its attachments. The five-year and longer time-frame criteria violations will be posted for review, evaluation and development of remedy alternatives by all interested parties. The PJM production of the reliability analysis raw results is expected to occur about ***January through July*** of each year. Posting of the results and stakeholder review and consideration of alternative remedies is expected to occur about ***February through August*** of each year. PJM will post TO and other stakeholder alternative upgrade remedies made available throughout this process. Throughout this time frame, TEAC typically has monthly or more frequent regularly scheduled meetings. PJM will periodically apprise TEAC of the progress of the violations identification and production of upgrade alternatives. Stakeholders may use these meetings to raise and discuss issues found in their reviews. Depending on the issues raised and input from stakeholders PJM may facilitate Subregional RTEP Committee meetings instead of or in addition to a scheduled TEAC meeting. These subregional meetings are intended for more focused review of subregional violations and alternative solutions.

Subregional RTEP Committee criteria violations and upgrade alternative meeting

This meeting is expected to occur, as may be necessary in various subregions, in the ***July / August*** timeframe each year. If a subregional meeting is unnecessary, the regularly scheduled TEAC meetings will provide the opportunity for that subregion's participants open discussion of violations and upgrades. In any event, all regional and subregional projects will be appropriately presented and reviewed at a TEAC meeting. Prior to a subregional violations and upgrade meeting, PJM will post the upgrade solutions that it proposes to remedy the identified criteria violations. At this subregional meeting PJM will present the reliability upgrades of specific violations and alternative upgrades as may be appropriate. By this Subregional RTEP Committee meeting, interested parties will have had the opportunity for ongoing participation in the ***February through August*** process of violation review and solution identification along with PJM and Transmission Owners. This subregional criteria violations and upgrade meeting is the forum for a final open discussion of the subregional reviews which have been occurring, prior to presentation to TEAC.

PJM TEAC Committee RTEP review

PJM expects that about ***August*** of each year, the final RTEP upgrade facilities will be available for presentation, review and endorsement at a scheduled TEAC meeting. PJM will post its recommendations of RTEP upgrades for identified violations as early as possible in the month prior to the TEAC meeting at which the final RTEP facilities will be reviewed (see RTEP@pjm.com.) This posting will distinguish facilities that are deemed Supplemental RTEP Projects. After the TEAC RTEP review meeting, there will be about a month of additional time for final written comments on the proposed RTEP facilities, after which the PJM Board will consider the final RTEP plan excluding Supplemental Projects for approval.

RTEP integrates Baseline Assumptions, Reliability Upgrades and Request Evaluations

PJM's robust energy market has attracted numerous requests from generator and transmission developers for interconnections with the Transmission System. These generator and transmission Interconnection Requests constitute a significant driver of regional transmission expansion needs. This subsection discusses this driver in the context of the RTEP preparation. Details of this process are contained in Manual 14A.

Requests for Long Term Firm Transmission Service and generator deactivations are other types of request that are evaluated and incorporated into RTEP.

Demand Response (DR) can be a load response solution to the need for transmission upgrades. DR solutions enter the PJM process in the Reliability Pricing Model (RPM) through the associated base residual and incremental auctions. The DR cleared in the auction is included in the assumptions for RTEP development and physically modeled in the baseline power flows. In this manner, load can mitigate or delay the need for RTEP upgrades.

The RTEP process baseline analyses include previously processed generators and transmission modifications as starting point assumptions. The current year RTEP evaluations performed on this baseline case are incremental to the baseline and establish a "revised" baseline for the year of the annual RTEP analysis. This revised baseline forms the starting case for the reviews of new interconnection requests. The new interconnection request analyses result in system modifications beyond RTEP upgrades that are caused by each interconnection request. New interconnection request evaluations also include a review of their effects on newly approved RTEP upgrades that are not yet committed to construction. If previously identified RTEP upgrades can be delayed because of a new interconnection request, the projects responsible for the upgrade deferrals will be credited for the benefits of the delayed need for the upgrades.

The RTEP integrates reliability upgrades, interconnection request upgrades and plan modifications and DR effects into a single process that accounts for the mutual interaction of the various market forces. In this way, transmission upgrades, interconnection requests and DR receive comparable treatment with respect to their opportunity to relieve transmission constraints.

Timing of Long-Term Firm Transmission Service Requests, and Generation and Transmission Interconnection Requests are based on the business needs of the party requesting the service. Such Requests, therefore, enter the RTEP planning process throughout the RTEP planning year.. Expansion plans that result from these individual project evaluations are incorporated into the RTEP after the system impact study stage. In addition, if needed to satisfy assumed planning reserve requirements for future planning year analyses, queue generators in earlier stages of the queue process may also be included. Only the queue generators with completed signed Interconnection Service Agreements, however, are allowed to be used to alleviate constraints.

This manual contains the details regarding the RTEP reliability planning process procedures. Refer to the introductory Manual 14 for references to the details associated with other elements of RTEP including the request and RPM processes.

RTEP Cost Responsibility for Required Enhancements

The RTEP encompasses two types of enhancements: Network Reinforcements and Direct Connection Attachment Facilities. Network Reinforcements can be required in order to accommodate the interconnection of a merchant project (generation or transmission) or to eliminate a Baseline problem as a result of system changes such as load growth, known transmission owner facility additions, etc. Merchant project driven upgrades are addressed in Manual 14A. The cost responsibility for each baseline-revealed Network Reinforcement is borne by transmission owners based on the contribution to the need for the network reinforcement. Such costs are recoverable by each transmission owner through FERC-filed transmission service rates. Network reinforcements may also be proposed by PJM to mitigate unhedgeable congestion. Allocation procedures for Baseline and Market Efficiency upgrades are discussed in Attachment A.

Overall, the RTEP is best understood from the perspective of the studies that revealed the recommended Plan enhancements. To that end, the Baseline Analysis and Impact Studies identify the enhancements required to meet defined NERC and applicable regional reliability council (Reliability First or VACAR/SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards.

RTEP Market Efficiency Planning

Market efficiency analysis is performed as part of the overall PJM Regional Transmission Expansion Planning (RTEP) process to accomplish the following two objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated.
2. Identify new transmission upgrades that may result in economic benefits.

PJM will perform a market efficiency analysis each year, following the availability of the appropriate updated RTEP power flow resulting from the reliability analysis process. As a result, there is a mechanism in place for regularly identifying transmission enhancements or expansions that will relieve transmission reliability violations that also have an economic impact. Constraints that have an economic impact include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) significant historical unhedgeable congestion; (3) pro-ration of Stage 1B ARR; or (4) significant future congestion as forecast in the market efficiency analysis.

In the market efficiency analysis, PJM will compare the costs and benefits of the economic-based transmission improvements. To calculate the benefits of these potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed accelerated reliability-based enhancements or the newly proposed economic-based enhancements for selected future years within the planning horizon of the RTEP. The relative benefits and costs of the economic-based enhancement or expansion must meet the benefit/cost ratio threshold test to be included in the RTEP recommended to the PJM Board of Managers for approval (This test and its implementation is described in detail in Attachment E.) PJM will also consider potential individual plans meeting objectives 1 or 2 resulting from the analyses of the posted congestion data by all stakeholders. PJM will present all the RTEP market efficiency enhancements to the TEAC Committee for review, comment and endorsement. Subsequent to TEAC review, PJM will address the TEAC review and present the final RTEP market efficiency plan to the PJM Board, along with the advice, comments, and recommendations of the TEAC Committee, for Board approval.

Market Efficiency Analysis and Stakeholder Process

PJM's market efficiency analysis involves several phases. The process begins with the determination of the congestion drivers that may signal market inefficiencies. PJM will collect and publicly post relevant drivers. These metrics will be reviewed by PJM and all stakeholders to assess the system areas that are most likely candidates for market efficiency upgrades. In addition, PJM will perform market simulations to determine projections of future market congestion based on the anticipated RTEP upgraded system. This process facilitates concurrent PJM and stakeholder review of the same information considered by PJM in preparation for PJM's solicitation of stakeholder input for upgrades that may economically alleviate market inefficiencies. This solicitation of input will be to the appropriate TEAC or Subregional RTEP Committee. Following the evaluation of congestion drivers and solicitation of remedies, PJM will initiate an analysis phase which first examines the potential economic costs and benefits that may be associated with any upgrades specified during the reliability analysis. After this assessment, PJM will evaluate the economic costs and benefits of any identified new potential upgrades target specifically at economic efficiency. The following information looks at each of these phases in more detail.

Determination and evaluation of historical congestion drivers

All PJM metrics of historical congestion drivers will be posted monthly throughout the year, except that AAR information will be posted as specified by the AAR auction process. This information can be found at:

(http://www.pjm.com/planning/epis.html)

PJM will calculate and post gross congestion costs by constraint for each constraint causing real-time off-cost operations. Gross congestion will be calculated as the product of the constraint shadow price times the load MWs at each load bus in the affected area times the load bus dfax where the affected area is defined as any bus with a dfax of 3% or greater.

PJM will calculate and post the Unhedgeable congestion cost statistics and associated constraints. Unhedgeable congestion costs will be calculated by taking the sum of load MWs at each load bus in the affected area times the relevant load bus dfax minus the sum of economic generation MWs at each generator bus in the affected area times the relevant generator bus dfax minus the sum of FTR MWs, and multiplying the resulting MW by the constraint shadow price. Economic generation is generation which is available and on-line and which, at its current level of output, has a bid price no greater than the PJM system marginal price. Self-scheduled generation is assigned a bid price of zero in the determination of economic generation MW.

Congestion causing a pro-ration of Stage 1A ARR requests will be determined and recommended for inclusion in the RTEP with a recommended in-service date based on the 10-year Stage 1A simultaneous feasibility analysis results. This recommendation will also include a high-level analysis of the cost and economic benefits of the upgrade as additional information but such upgrades will not be subject to market efficiency cost/benefit analysis. More information on the ARR allocation auction process can be found in Manual 6 titled PJM Capacity Market.

Congestion causing pro-ration of Stage 1B ARR requests will be addressed using the "with and without" analysis and the benefit/cost ratio threshold described previously in this market efficiency material.

Determination of projected congestion drivers and potential remedies

PJM will provide all stakeholders with estimates of the projected congestion by performing annual hourly market simulations of future years using a commercially available market analysis software modeling tool (see assumptions and criteria material in Section 1.) This simulation will produce and PJM will post projected binding constraints, binding hours, average economic impact of binding constraints, and cumulative economic impact of binding constraints for the four RTEP market efficiency analyses (current year plus 1, current year plus 4, current year plus 7 and current year plus 12.)

This analysis is expected to be completed about the ***third quarter*** of the RTEP cycle year. At this time PJM will also facilitate a TEAC or Subregional RTEP Committee meeting, as appropriate, to review congestion and solicit feedback from the stakeholders' review of the projected congestion data as well as the historical congestion data. All stakeholders can provide input to PJM's consideration of the congestion data and potential upgrades to be considered for market efficiency solutions to identified economic issues.

The timing of this meeting will depend, to some extent, on the complexity of the analysis, however, it is anticipated that this meeting will occur during the ***third quarter*** of each year. At this meeting, PJM will provide a summary of the analysis results and a description of any congested areas that will be analyzed using Market Efficiency analysis. PJM will also provide a high-level estimate of the transmission upgrades then being considered. At the completion of this stakeholder review, any member of the TEAC can provide additional written comments within sixty (60) days of this meeting.

Stakeholder Written Comments

These written comments will consist of three (3) sections:

- Introduction, which will describe the party submitting the comments and their reason for submitting these comments
- Summary, which will consist of no more than 3 pages summarizing the positions described in the written comments
- Discussion, which will consist of no more than 20 pages describing in detail the positions taken by the party

Parties wishing formally to submit alternative proposals of their own are encouraged to do so separately, as described further, below.

The Office of the Interconnection will have the responsibility of compiling comments from TEAC participants. All written comments will be posted to the PJM web site and provided to the PJM Board of Managers together with a PJM staff summary that will focus on conveying the following: (1) the issues; (2) the parties raising the issues; and, (3) as may be appropriate, PJM's discussion of ramifications of the issues. Communication to the Board of Managers will not include results of any voting.

Evaluation of cost / benefit of advancing reliability projects

PJM will perform annual market simulations and produce cost / benefit analysis of advancing reliability projects. An initial set of simulations will be conducted for each of the four years (current year plus 1, current year plus 4, current year plus 7 and current year plus 10) using the "as is" transmission network topology without modeling future RTEP upgrades. A second set of simulations will be conducted for each of the four years using the as planned RTEP upgrades. A comparison of the "as is" and "as planned" simulations will identify constraints which have caused significant historical or simulated congestion costs but for which an as-planned upgrade will eliminate or relieve the congestion costs to the point that the constraint is no longer an economic concern. A comparison of these simulations will also reveal if a particular RTEP upgrade is a candidate for acceleration or expansion. For example, if a constraint causes significant congestion in year 7 but not in year 10 then the upgrade which eliminates this congestion in the year 10 simulation may be a candidate for acceleration. The benefit of accelerating this upgrade would then be compared to the cost of acceleration as described below before recommendation for acceleration is made.

When the reliability project economic acceleration analyses have been completed, PJM will schedule a TEAC or Subregional Committee meeting, as appropriate, to review the results. The timing of this meeting will depend, to some extent, on the amount and complexity of analysis that must be performed. However, it is anticipated that this meeting will take place during the ***fourth quarter*** of each year. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis and a description of any recommendations for accelerating reliability projects based on economic considerations.

Determination and evaluation of cost / benefit of potential RTEP projects specifically targeted for economic efficiency

PJM will perform annual market simulations and produce cost / benefit analysis of projects specifically targeted for economic efficiency. The net present value of annual benefits will be calculated for the first 15 years of upgrade life and compared to the net present value of the upgrade revenue requirement for the same 15 year period.

An initial set of simulations will be conducted for each of four years (current year plus 1, current year plus 4, current year plus 7 and current year plus 10) using the as planned transmission network topology as defined by the most recent RTEP. A second set of simulations will be conducted for each of the four years using the as planned transmission network topology plus the upgrade being studied. The upgrade will be included in each of the four simulation years regardless of the actual anticipated in-service date of the upgrade. A comparison of these simulations will identify the benefit of the upgrade in each of the four years analyzed. Annual benefits within the 10-year time frame for years which were not simulated would be interpolated using these simulation results. A forecast of annual benefits for years beyond the 10-year simulation time frame would be based on an extrapolation of the market simulation results from the studied years. A higher-level annual market simulation will be made for future year 15 to validate the extrapolation results and the extrapolation of annual benefits for years beyond the 10-year simulation time frame may be adjusted accordingly. This high level simulation of future year 15 may require a less detailed model of the transmission system below the 500 kV level.

An extrapolation of the simulation results will provide a forecast of annual upgrade benefits for each of the anticipated first 15 years of upgrade life, beginning from the projects anticipated in-service date. The present value of annual benefits projected for the first 15 years of upgrade life will be compared to the present value of the upgrade revenue requirement for the same 15 year period to determine if the upgrade is cost beneficial and recommended for inclusion in the PJM RTEP. If the ratio of the present value of benefits to the present value of costs exceeds 1.25 then the upgrade is recommended for inclusion in the RTEP.

For each upgrade which is recommended for inclusion in the RTEP, PJM will provide the level of new generation or DSM per region that would eliminate the need for the transmission upgrade.

When the economic efficiency project evaluations have been completed, PJM will schedule a TEAC or Subregional Committee meeting, as appropriate, to review the results. The timing of this meeting may depend on the amount and complexity of analysis that must be performed. It is, however, anticipated that this meeting will take place ***by April*** of the calendar year that begins the subsequent RTEP planning cycle. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis, and a description of any recommendations for economic efficiency projects.

Determination of final RTEP market efficiency upgrades

PJM will perform a combined review of the accelerated reliability projects and new market efficiency projects that passed the economic screening tests to determine if there are potential upgrades with electrical similarities. This may result in new projects to replace the original projects to form a more efficient overall market solution. Stakeholders may also suggest such potential synergies. PJM will evaluate the cost / benefits of any such resulting "hybrid" projects[3]. The final list of reliability projects and market efficiency projects, including any "hybrid" projects will be presented and discussed at a ***second quarter (April)*** TEAC meeting. At this TEAC meeting PJM will review all the Market efficiency plans resulting from this cycle of market efficiency studies. Recommended projects will be taken to the PJM Board for endorsement, and will either be included in subsequent RTEP analysis if there is a "volunteer" to build the project, or a report will be filed with FERC in accordance with Schedule 6 of the PJM Operating Agreement. As part of this request for endorsement, PJM

3 Hybrid transmission upgrades include proposed solutions which encompass modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

will provide the written comments submitted by the parties, and will discuss these written comments with the PJM Board.

Within the limits of confidential, market sensitive, trade secret, and proprietary information, PJM will make all of the information used to develop the Market Efficiency recommendations available to market participants to use in their own, independent analyses.

For each enhancement which is analyzed, PJM will calculate and post on its website changes in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs); (ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new economic-based enhancement or expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Reliability Pricing Model construct.

For each market efficiency project proposed for RTEP, PJM will also post, as soon as practical, the following:

a. Anticipated high-level project schedule and milestone dates
b. Final commitment date after which any change to input factors or drivers will not result in transmission project deferral or cancellation.

After this TEAC meeting, any member of the TEAC can provide written comments within sixty (60) days of this meeting. These written comments will consist of three (3) sections:

- Introduction, which will describe the party submitting the comments and their reason for submitting these comments
- Summary, which will consist of no more than 3 pages summarizing the positions described in the written comments
- Discussion, which will consist of no more than 20 pages describing in detail the positions taken by the party

Submitting Alternative Proposals

Any TEAC member or other entity (consistent with PJM Operating Agreement Schedule 6 provisions), may formally submit alternative proposals for evaluation under the Market Efficiency analysis at any time, but no later than **December 31st** of each year RTEP cycle year in order to be considered in the then-current planning cycle (the RTEP market efficiency planning analysis carries over from the RTEP cycle year into the first quarter of the following RTEP planning cycle year.) These alternatives will be posted on the PJM Website. PJM will consider these alternatives, and establish the final set of proposals to be included in market efficiency analysis. The process of formally submitting proposals is not limited to transmission solutions but may also include generation solutions via PJM's established interconnection queue process; or, demand side management and load management proposals as well. Alternatively, market projects to relieve congestion can be submitted by market participants through the queue process at any time. PJM will evaluate these projects under the then current business rules contained in the PJM Tariff and Operating Agreement.

Regardless of all proposals considered – whether proposed by PJM or other parties - PJM will establish a "go/no-go" decision-point deadline (or final commitment date) after which existing RTEP transmission components will not be deferred or cancelled. This will provide certainty to developers, owners and investors.

Ongoing Review of Project Costs

To assure that projects selected by the PJM Board for Market Efficiency continue to be economically beneficial, both the costs and benefits of these projects will periodically be reviewed, nominally on an annual basis. Substantive changes in the costs and/or benefits of these projects will be reviewed with the TEAC at a subsequent meeting to determine if these projects continue to provide measurable economic benefit and should remain in the RTEP.

For projects with a total cost exceeding $50 million, an independent review of project costs and benefits will be performed to assure both consistency of estimating practices across PJM and that the scope of the project is consistent with the project as proposed in the Market Efficiency analysis.

Evaluation of Operational Performance Issues

As per Schedule 6, section 1.5 of the PJM Operating Agreement, PJM is required to address operational performance issues and include system enhancements, as may be appropriate, to adequately address identified problems. To fulfill this obligation, PJM Transmission Planning staff and Operations Planning staff annually review actual operating results to assess the need for transmission upgrades that would address identified issues. Typical operating areas of interest in these reviews include Transmission Loading Relief (TLR) and Post Contingency Local Load Relief Warning (PCLLRW) events.

The first operational performance issue to be addressed through the RTEP was an upgrade of the Wylie Ridge 500/345 kV transformation. The metric applied to designate Wylie Ridge an operational performance issue was the TLR metric. This same metric is applied consistently across the PJM footprint.

In addition, PJM has also developed and initiated use of a tool for Probabilistic Risk Assessment (PRA) of transmission infrastructure. PJM's 500/230 kV transformer infrastructure has been identified as particularly suited for assessment using this tool. PRA is further discussed in following sections.

Operational Performance Metrics

Events and metrics considered in the annual operational performance reviews are not limited to a specifically defined list and will be responsive to events and conditions that may arise. In addition, PJM stakeholders may raise operational issues to PJM's attention for consideration during the RTEP process through interactions with the Planning, TEAC or Subregional RTEP Committees.

The PJM TLR metric identifies facilities that result in over 1,000 hours or 100 occurrences of TLR level 3 or higher on an annual basis. These facilities will be evaluated through the RTEP process for system enhancement.

For PCLLRW events, PJM will review all such events after the conclusion of the peak season. The initiating facilities will be determined and the expected impacts of planned

RTEP upgrades will be reviewed and the need for additional planned upgrades will be evaluated.

PRA evaluation uses an economic analysis of the cost of the investment that mitigates a risk and the dollar value of the avoided risk. The mitigation strategy cost, prime rate and payback period are used to determine if the strategy cost is less than the value of risk. Projects with lower cost than risk are candidates for the RTEP.

Probabilistic Risk Assessment of PJM 500/230 kV Transformers

One significant element of PJM's operational performance reviews involves a risk evaluation aimed at anticipating significant transmission loss events. PJM integrates aging infrastructure decisions into the ongoing RTEP process: analysis, plan development, stakeholder review, PJM Board approval, and implementation, over PJM's entire footprint. Thus, the aging infrastructure initiative implements a proactive, PJM-wide approach to assess the risk of transmission facility loss and to mitigate operational and market impacts of such losses.

PRA's initial implementation at PJM is a risk management tool employed to reduce the potential economic and reliability consequences of transmission system equipment losses. In collaboration with academia, vendors and member TOs, PJM integrated various input drivers into a transformer PRA initiative to manage 500/230 kV transformer risk. In the case of the 500/230 kV transformers, risk is the product of the probability of incurring a loss and the economic consequence of the loss. Probability of loss is determined based on the individual transformer unit's condition assessments and vintage history. Economic loss impact is based upon the duration of the loss and the accumulation of unhedgeable congestion costs, or the increased cost of running out of merit generation to meet load requirements after a transformer loss. If lead times for 500/230 kV transformer units are as great as eighteen months, then outage durations can be long if adequate loss mitigation is not in place. The PRA outputs the annual risk to the PJM system of each transformer unit in terms of dollars. The annual risk dollars are then used to justify mitigating solutions such as redundant bank deployment, proactive replacement or adding spares. The deployment strategy chosen will depend on the level of risk mitigation and reliability benefit.

While initially developed for aging 500/230 kV transformers, the PRA tool is capable of assessing other equipment types and other transformer voltage classes. The PRA tool is commercially available software.