Appendix 1-A: Economic Dispatch Analysis

Draft Environmental Impact Statement

Cricket Valley Energy Project – Dover, NY

GE
Energy

Cricket Valley Energy Project: Security-Constrained Economic Dispatch Analysis

***Prepared for:* GE Energy Global Development and Strategic Initiatives**

Prepared by: Energy Applications and Systems Engineering

imagination at work

Foreword

General Electric International, Inc prepared this document as a service through the Energy Applications and Systems Engineering group. It is submitted to:

David Malcolm

GE Energy Global Development and Strategic Initiatives.

Technical correspondence concerning this document should be referred to:

Steven Oltmanns

GE Energy, Principal

Energy Applications and Systems Engineering

1333 West Loop South
Houston, TX 77027
(713) 803-0375
steven.oltmanns@ge.com

Commercial questions and correspondence concerning this document should be referred to:

David Houghtaling

GE Energy, Commercial Operations Manager

Energy Applications and Systems Engineering

1 River Road
Schenectady, NY 12345
Phone #: 518-385-4196
david.houghtaling@ge.com

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Legal Notice

This report was prepared by General Electric International, Inc. as an account of work sponsored by GE Energy Global Development and Strategic Initiatives. Neither GE Energy Global Development and Strategic Initiatives or GE, nor any person acting on their behalf:

1. Makes any warranty or representation, expressed or implied, with respect to the use of any information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights.
2. Assumes any liabilities with respect to the use of or for damage resulting from the use of any information, apparatus, method, or process disclosed in this report.

Copyright © 2010 GE Energy. All rights reserved

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Table of Contents

FOREWORD II

LEGAL NOTICE III

TABLE OF CONTENTS IV

1 EXECUTIVE SUMMARY 1

2 ANALYSIS 2

3 RESULTS 4

4 INDIAN POINT UNIT 2 RETIREMENT SENSITIVITY RESULTS 8

5 *APPENDIX A* – GE-MAPS™ DATABASE DOCUMENTATION (EASTERN INTERCONNECTION (EI) DATABASE, REVISION 1.6, AUGUST 6, 2010) 11

6 *APPENDIX B* - GE-MAPS™ BROCHURE 12

7 *APPENDIX C* - INDIAN POINT UNIT 2 RETIREMENT SCENARIO COMPARISON 13

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

1 Executive Summary

GE Energy Global Development and Strategic Initiatives (GDSI) contacted the Energy Applications and Systems Engineering (EA&SE) group to conduct a Security-Constrained Economic Dispatch (SCED) study in support of the Environmental Impact Study (EIS) for the proposed 1,000 MW Cricket Valley Energy Project (Cricket Valley) in New York. To perform the SCED study, EA&SE used GE Energy's Multi-Area Production Simulation (GE-MAPS™) software application for a transmission constrained, production simulation of the regions surrounding Cricket Valley within the Eastern Interconnection (EI) for years 2015 through 2020. This was accomplished by incorporating cost and performance assumptions specific to the Cricket Valley in EA&SE's current non-proprietary EI database.

Generally speaking, the addition of Cricket Valley to the New York Pool results in an increase in energy production within the NY Pool, fewer imports from adjacent pools and a lower Total Annual Load-Weighted Cost to Serve (M$ per year) across the region (New York, New England, PJM and Ontario). Generally speaking, both NOx and SO2 production (total tons per year) decrease across the region and within most pools, while Ontario shows a slight increase in both effluents in certain years (due to a slight increase in Ontario coal-fired generation, with the addition of Cricket Valley). Total CO2 production (total tons per year) across the region decreases as a result of Cricket Valley, but the total amount of CO2 produced in the NY Pool increases slightly (about 2% annually over the study period), due to the increase energy production (about 2% annually over the study periods) within the NY Pool.

A sensitivity analysis was also performed to consider the possible retirement of a nuclear generating unit in the region. Currently, the EI database used for this SCED study assumes the Indian Point Units 2 and 3 will receive an operating license extension beyond the current operating licenses, due to expire in September 2013 and December 2015, respectively. For purposes of this study, it did not seem unreasonable to assume a scenario where the operating license for Unit 2 may not be extended beyond September 2013.

The results from the Indian Point Unit 2 sensitivity cases are summarized in Section 4 below. In general, the relative impact of adding Cricket Valley to the New York Pool with Indian Point Unit 2 retired in 2013 is consistent with the observed results assuming Indian Point Unit 2 remains in service beyond the expiration of its current operating license.

Licenses for the GE-MAPS software application and the EI database used for this study are not included as deliverables for this study.

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

2 Analysis

EA&SE performed the SCED study by incorporating cost and performance assumptions specific to the Cricket Valley in EA&SE's current non-proprietary EI database. (See Appendix A for a summary of the non-proprietary database assumptions.) The assumptions for Cricket Valley are summarized below:

Table 2.1: Cricket Valley Cost and Performance Assumptions

Parameter	Assumption
GE-MAPS Gas Node:	NGNYEAST
Summer Capacity:	912 MW CC (+ 124 MW Duct Firing)
Winter Capacity:	962 MW CC (+ 122 MW Duct Firing)
Summer FLHR:	6,654 Btu/kWh
Winter FLHR:	6,657 Btu/kWh
Duct Firing IHR (Summer):	9,045 Btu/kWh
Duct Firing IHR (Winter):	9,049 Btu/kWh
NOx Rate:	2.0 ppm
Variable O&M:	$2.45/MWh
Fixed O&M:	$12.00/kW-yr
Start-Up Cost:	$36,000/start
COD:	May 1, 2015
Forced Outage Rate:	3.3%
Planned Outage Rate:	4.0%
Min Down Time:	8 hours
Inflation Rate:	2.4%
Interconnection:	345 kV line from Pleasant Valley to Long Mountain approximately 9 miles from Pleasant Valley

Using these assumptions, EA&SE performed a transmission constrained, production simulation using the GE-MAPS software application (see Appendix B for a summary brochure describing the GE-MAPS software application). Two production simulations were performed: one case without Cricket Valley (Base Case) and a second case with Cricket Valley (Cricket Valley Case). Using the results from these two simulations, the impact of Cricket Valley on the New York ISO and on adjacent systems (ISO-New England, PJM, Ontario IESO) was analyzed. The variables selected for this analysis include Total Annual Load-Weighted Cost to Serve (M$), Total Annual Energy Production (GWh) and Total Annual Emissions Production (NOx, SO2 and CO2) for each of the four "pools" analyzed (NY Pool, NE Pool, Ontario and PJM).

The results from these two cases are summarized in Section 3 below.

A sensitivity analysis was also performed to consider the possible retirement of a nuclear generating unit in the region. Currently, the EI database used for this SCED study assumes

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

the Indian Point Units 2 and 3 will receive an operating license extension beyond the current operating licenses, due to expire in September 2013 and December 2015, respectively.[1] The recent New York State Energy Research Development Authority (NYSERDA) State Energy Plan[2] included a scenario where both Units 2 and 3 were retired in 2015.[3] While the likelihood of retiring both nuclear units in the same year may appear questionable today, it did not seem unreasonable for purposes of this study to assume a scenario where the operating license for Unit 2 may not be extended beyond September 2013.

The results from the Indian Point Unit 2 sensitivity cases are summarized in Section 4 below.

[1] http://www.entergy-nuclear.com/plant_information/indian_point.aspx

[2] http://www.nysenergyplan.com/

[3] http://www.nysenergyplan.com/Supporting_Documents/Electricity%20Modeling%20Assumptions.pdf?cf03800915=C307807C!MjA0MDUxNTAxOmNvcnByYWRpdXNzc286vQh0XRLzhAsnwQhEoGFlnw==

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

3 Results

Table 3.1 below summarizes the Total Cost to Serve in each of the pools analyzed. The underlying competitive wholesale market structure within each of these pools assumes supply offers based on each individual unit's marginal costs. Generally speaking, the majority of the decrease in Total Cost to Serve is shared between the NY Pool and PJM.

Table 3.1 Total Annual Load-Weighted Cost to Serve (M$) by Pool

		2015	2016	2017	2018	2019	2020
Base Case (M$)	NE Pool	$ 8,215	$ 8,545	$ 8,856	$ 9,090	$ 9,709	$ 9,957
	NY Pool	$ 10,586	$ 11,086	$ 11,400	$ 11,704	$ 12,532	$ 12,842
	Ontario	$ 6,872	$ 7,485	$ 7,678	$ 8,085	$ 8,303	$ 8,635
	PJM	$ 43,081	$ 45,087	$ 45,209	$ 46,964	$ 49,922	$ 51,825
	TOTAL	$ 68,755	$ 72,203	$ 73,143	$ 75,843	$ 80,465	$ 83,259
Cricket Valley Case (M$)	NE Pool	$ 8,124	$ 8,383	$ 8,729	$ 8,903	$ 9,545	$ 9,759
	NY Pool	$ 10,425	$ 10,869	$ 11,211	$ 11,429	$ 12,280	$ 12,608
	Ontario	$ 6,853	$ 7,454	$ 7,677	$ 8,024	$ 8,261	$ 8,564
	PJM	$ 42,911	$ 44,819	$ 44,968	$ 46,727	$ 49,581	$ 51,630
	TOTAL	$ 68,312	$ 71,524	$ 72,585	$ 75,082	$ 79,667	$ 82,562
Increase (Decrease) (M$)	NE Pool	$ (92)	$ (162)	$ (128)	$ (188)	$ (164)	$ (198)
	NY Pool	$ (162)	$ (217)	$ (189)	$ (275)	$ (252)	$ (234)
	Ontario	$ (20)	$ (32)	$ (2)	$ (61)	$ (42)	$ (71)
	PJM	$ (170)	$ (269)	$ (240)	$ (237)	$ (340)	$ (195)
	TOTAL	$ (443)	$ (679)	$ (559)	$ (761)	$ (798)	$ (697)
% Increase (Decrease)	NE Pool	(1.1%)	(1.9%)	(1.4%)	(2.1%)	(1.7%)	(2.0%)
	NY Pool	(1.5%)	(2.0%)	(1.7%)	(2.4%)	(2.0%)	(1.8%)
	Ontario	(0.3%)	(0.4%)	(0.0%)	(0.8%)	(0.5%)	(0.8%)
	PJM	(0.4%)	(0.6%)	(0.5%)	(0.5%)	(0.7%)	(0.4%)
	TOTAL	(0.6%)	(0.9%)	(0.8%)	(1.0%)	(1.0%)	(0.8%)

Table 3.2 below illustrates the impact on total energy production within each pool, as a result of adding Cricket Valley to the NY Pool. Generally speaking, the increase in energy production within New York serves to decrease imports from adjacent pools, thereby lowering energy production in each of those pools.

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Table 3.2 Total Annual Energy Production (GWh) by Pool

		2015	2016	2017	2018	2019	2020
Base Case (GWh)	NE Pool	120,492	121,789	122,396	124,031	126,229	127,615
	NY Pool	148,035	149,226	153,738	156,701	158,174	163,212
	Ontario	143,708	144,511	144,216	144,244	144,654	144,829
	PJM	735,037	739,106	747,167	751,786	758,825	757,786
	TOTAL	1,147,272	1,154,633	1,167,517	1,176,762	1,187,881	1,193,441
Cricket Valley Case (GWh)	NE Pool	119,674	120,728	121,214	122,893	125,006	126,396
	NY Pool	150,004	152,267	156,927	159,768	161,550	166,495
	Ontario	143,742	144,363	143,983	144,005	144,417	144,650
	PJM	733,950	737,463	745,492	750,115	756,998	755,926
	TOTAL	1,147,370	1,154,820	1,167,616	1,176,780	1,187,971	1,193,468
Increase (Decrease) (GWh)	NE Pool	(818)	(1,061)	(1,182)	(1,138)	(1,223)	(1,219)
	NY Pool	1,969	3,040	3,190	3,067	3,376	3,283
	Ontario	34	(149)	(233)	(239)	(237)	(178)
	PJM	(1,087)	(1,644)	(1,675)	(1,672)	(1,827)	(1,860)
	TOTAL	98	187	99	17	90	27
% Increase (Decrease)	NE Pool	(0.7%)	(0.9%)	(1.0%)	(0.9%)	(1.0%)	(1.0%)
	NY Pool	1.3%	2.0%	2.1%	2.0%	2.1%	2.0%
	Ontario	0.0%	(0.1%)	(0.2%)	(0.2%)	(0.2%)	(0.1%)
	PJM	(0.1%)	(0.2%)	(0.2%)	(0.2%)	(0.2%)	(0.2%)
	TOTAL	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Tables 3.3 through 3.5 below summarize the total impact on emissions production within each pool as a result of adding Cricket Valley to the NY Pool. Generally speaking, both NOx and SO2 production decrease across the region and within most pools, while Ontario shows a slight increase in both effluents in certain years.

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Table 3.3 Total Annual NOx Production (Tons) by Pool

		2015	2016	2017	2018	2019	2020
Base Case (Tons)	NE Pool	14,398	14,529	15,530	14,737	15,068	15,144
	NY Pool	26,254	26,788	27,677	26,998	27,916	27,926
	Ontario	2,102	2,133	2,106	2,100	2,080	2,096
	PJM	320,234	316,280	327,105	318,475	318,351	311,774
	TOTAL	362,988	359,730	372,417	362,310	363,415	356,941
Cricket Valley Case (Tons)	NE Pool	14,249	14,324	15,329	14,518	14,846	14,914
	NY Pool	25,817	26,231	27,118	26,408	27,338	27,308
	Ontario	2,105	2,127	2,096	2,093	2,075	2,096
	PJM	319,756	315,518	326,276	317,679	317,584	311,149
	TOTAL	361,926	358,199	370,818	360,698	361,844	355,466
Increase (Decrease) (Tons)	NE Pool	(149)	(205)	(201)	(219)	(222)	(230)
	NY Pool	(437)	(557)	(559)	(590)	(578)	(618)
	Ontario	4	(6)	(10)	(7)	(5)	(1)
	PJM	(479)	(763)	(829)	(796)	(767)	(626)
	TOTAL	(1,061)	(1,531)	(1,599)	(1,612)	(1,571)	(1,475)
% Increase (Decrease)	NE Pool	(1.0%)	(1.4%)	(1.3%)	(1.5%)	(1.5%)	(1.5%)
	NY Pool	(1.7%)	(2.1%)	(2.0%)	(2.2%)	(2.1%)	(2.2%)
	Ontario	0.2%	(0.3%)	(0.5%)	(0.3%)	(0.2%)	(0.0%)
	PJM	(0.1%)	(0.2%)	(0.3%)	(0.2%)	(0.2%)	(0.2%)
	TOTAL	(0.3%)	(0.4%)	(0.4%)	(0.4%)	(0.4%)	(0.4%)

Table 3.4 Total Annual SO2 Production (Tons) by Pool

		2015	2016	2017	2018	2019	2020
Base Case (Tons)	NE Pool	75,077	75,905	83,425	76,414	77,512	78,309
	NY Pool	51,076	52,364	55,576	53,185	54,031	54,090
	Ontario	20,228	20,449	20,164	20,094	19,668	19,898
	PJM	1,807,060	1,756,709	1,795,020	1,743,189	1,730,725	1,674,074
	TOTAL	1,953,440	1,905,428	1,954,186	1,892,882	1,881,936	1,826,370
Cricket Valley Case (Tons)	NE Pool	74,660	75,354	83,120	76,068	76,957	77,899
	NY Pool	50,437	51,329	55,081	52,465	53,116	53,007
	Ontario	20,267	20,440	20,141	20,119	19,710	19,963
	PJM	1,805,210	1,753,217	1,791,724	1,739,698	1,727,205	1,671,250
	TOTAL	1,950,574	1,900,342	1,950,066	1,888,349	1,876,988	1,822,120
Increase (Decrease) (Tons)	NE Pool	(417)	(551)	(305)	(346)	(554)	(409)
	NY Pool	(638)	(1,035)	(495)	(721)	(915)	(1,082)
	Ontario	39	(9)	(23)	25	42	65
	PJM	(1,850)	(3,491)	(3,296)	(3,491)	(3,520)	(2,823)
	TOTAL	(2,867)	(5,086)	(4,120)	(4,533)	(4,948)	(4,250)
% Increase (Decrease)	NE Pool	(0.6%)	(0.7%)	(0.4%)	(0.5%)	(0.7%)	(0.5%)
	NY Pool	(1.2%)	(2.0%)	(0.9%)	(1.4%)	(1.7%)	(2.0%)
	Ontario	0.2%	(0.0%)	(0.1%)	0.1%	0.2%	0.3%
	PJM	(0.1%)	(0.2%)	(0.2%)	(0.2%)	(0.2%)	(0.2%)
	TOTAL	(0.1%)	(0.3%)	(0.2%)	(0.2%)	(0.3%)	(0.2%)

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Table 3.5 below illustrates that, while total CO2 production across the region decreases as a result of Cricket Valley, the total amount of CO2 produced in the NY Pool increases slightly (about 2% annually over the study period), due to the increase energy production (about 2% annually over the study periods) within the NY Pool (Table 3.2).

Table 3.5 Total Annual CO2 Production (Tons) by Pool

		2015	2016	2017	2018	2019	2020
Base Case (Tons)	NE Pool	43,129,318	43,086,285	44,978,154	44,289,028	44,835,766	45,601,366
	NY Pool	43,479,260	43,781,477	45,125,219	44,716,534	46,314,790	46,331,325
	Ontario	9,320,627	9,541,108	9,440,267	9,427,543	9,548,769	9,557,390
	PJM	426,452,174	424,264,527	432,499,292	427,210,980	427,827,876	419,341,384
	TOTAL	522,381,380	520,673,397	532,042,932	525,644,086	528,527,200	520,831,466
Cricket Valley Case (Tons)	NE Pool	42,753,795	42,587,434	44,444,738	43,764,002	44,243,532	45,028,331
	NY Pool	43,986,254	44,688,292	46,123,903	45,664,163	47,390,749	47,351,628
	Ontario	9,335,598	9,471,738	9,331,756	9,323,678	9,451,650	9,491,943
	PJM	425,756,207	423,291,330	431,516,247	426,175,425	426,738,014	418,270,603
	TOTAL	521,831,855	520,038,794	531,416,643	524,927,268	527,823,945	520,142,505
Increase (Decrease) (Tons)	NE Pool	(375,523)	(498,851)	(533,416)	(525,026)	(592,234)	(573,036)
	NY Pool	506,994	906,815	998,684	947,628	1,075,959	1,020,303
	Ontario	14,971	(69,369)	(108,511)	(103,865)	(97,119)	(65,447)
	PJM	(695,966)	(973,197)	(983,045)	(1,035,555)	(1,089,862)	(1,070,781)
	TOTAL	(549,525)	(634,602)	(626,288)	(716,818)	(703,256)	(688,961)
% Increase (Decrease)	NE Pool	(0.9%)	(1.2%)	(1.2%)	(1.2%)	(1.3%)	(1.3%)
	NY Pool	1.2%	2.1%	2.2%	2.1%	2.3%	2.2%
	Ontario	0.2%	(0.7%)	(1.1%)	(1.1%)	(1.0%)	(0.7%)
	PJM	(0.2%)	(0.2%)	(0.2%)	(0.2%)	(0.3%)	(0.3%)
	TOTAL	(0.1%)	(0.1%)	(0.1%)	(0.1%)	(0.1%)	(0.1%)

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

4 Indian Point Unit 2 Retirement Sensitivity Results

In general, while the impact of retiring Indian Point Unit 2 results in an increase in the Total Annual Load-Weighted Cost to Serve and overall emissions production across the region (Appendix C), the relative impact of adding Cricket Valley to the New York Pool with Indian Point Unit 2 retired in 2013 is consistent with the observed results assuming Indian Point Unit 2 remains in service beyond the expiration of its current operating license. Table 4.1 below summarizes the impact of Cricket Valley on the Total Cost to Serve in each of the pools analyzed, assuming Indian Point Unit 2 is retired.

Table 4.1 Total Annual Load-Weighted Cost to Serve (M$) by Pool

		2015	2016	2017	2018	2019	2020
Base Case w/ Indian Point Unit 2 Retirement (M$)	NE Pool	$ 8,262	$ 8,570	$ 8,912	$ 9,141	$ 9,759	$ 10,031
	NY Pool	$ 10,940	$ 11,431	$ 11,721	$ 12,053	$ 12,927	$ 13,260
	Ontario	$ 6,847	$ 7,492	$ 7,700	$ 8,091	$ 8,328	$ 8,637
	PJM	$ 43,357	$ 45,405	$ 45,384	$ 47,163	$ 50,074	$ 52,093
	TOTAL	$ 69,406	$ 72,897	$ 73,717	$ 76,447	$ 81,088	$ 84,022
Cricket Valley Case w/ Indian Point Unit 2 Retirement (M$)	NE Pool	$ 8,159	$ 8,407	$ 8,760	$ 8,952	$ 9,589	$ 9,824
	NY Pool	$ 10,792	$ 11,217	$ 11,527	$ 11,814	$ 12,693	$ 13,029
	Ontario	$ 6,841	$ 7,467	$ 7,693	$ 8,056	$ 8,279	$ 8,578
	PJM	$ 43,215	$ 45,164	$ 45,147	$ 46,981	$ 49,816	$ 51,922
	TOTAL	$ 69,007	$ 72,255	$ 73,127	$ 75,803	$ 80,377	$ 83,353
Increase (Decrease) (M$)	NE Pool	$ (103)	$ (163)	$ (152)	$ (189)	$ (171)	$ (207)
	NY Pool	$ (148)	$ (214)	$ (194)	$ (239)	$ (234)	$ (231)
	Ontario	$ (5)	$ (24)	$ (7)	$ (34)	$ (49)	$ (60)
	PJM	$ (143)	$ (241)	$ (237)	$ (181)	$ (258)	$ (170)
	TOTAL	$ (400)	$ (643)	$ (590)	$ (645)	$ (711)	$ (669)
% Increase (Decrease)	NE Pool	(1.3%)	(1.9%)	(1.7%)	(2.1%)	(1.7%)	(2.1%)
	NY Pool	(1.4%)	(1.9%)	(1.7%)	(2.0%)	(1.8%)	(1.7%)
	Ontario	(0.1%)	(0.3%)	(0.1%)	(0.4%)	(0.6%)	(0.7%)
	PJM	(0.3%)	(0.5%)	(0.5%)	(0.4%)	(0.5%)	(0.3%)
	TOTAL	(0.6%)	(0.9%)	(0.8%)	(0.8%)	(0.9%)	(0.8%)

Table 4.2 below illustrates the impact on total energy production within each pool, as a result of adding Cricket Valley to the NY Pool, assuming Indian Point Unit 2 is retired.

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Table 4.2 Total Annual Energy Production (GWh) by Pool

		2015	2016	2017	2018	2019	2020
Base Case w/ Indian Point Unit 2 Retirement (GWh)	NE Pool	121,512	122,774	123,449	125,113	127,217	128,676
	NY Pool	144,810	146,109	150,600	153,206	154,922	159,744
	Ontario	143,718	144,518	144,243	144,382	144,744	145,008
	PJM	737,154	741,074	749,241	753,912	760,895	759,867
	TOTAL	1,147,195	1,154,475	1,167,534	1,176,612	1,187,778	1,193,294
Cricket Valley Case w/ Indian Point Unit 2 Retirement (GWh)	NE Pool	120,688	121,692	122,261	123,941	125,960	127,362
	NY Pool	146,962	149,458	154,156	156,684	158,779	163,429
	Ontario	143,763	144,383	144,077	144,090	144,487	144,766
	PJM	735,832	739,110	747,014	752,018	758,693	757,845
	TOTAL	1,147,245	1,154,643	1,167,508	1,176,733	1,187,920	1,193,402
Increase (Decrease) (GWh)	NE Pool	(824)	(1,082)	(1,188)	(1,172)	(1,256)	(1,314)
	NY Pool	2,152	3,349	3,555	3,479	3,857	3,686
	Ontario	45	(135)	(167)	(292)	(257)	(241)
	PJM	(1,323)	(1,964)	(2,227)	(1,894)	(2,202)	(2,022)
	TOTAL	50	168	(26)	121	142	108
% Increase (Decrease)	NE Pool	(0.7%)	(0.9%)	(1.0%)	(0.9%)	(1.0%)	(1.0%)
	NY Pool	1.5%	2.3%	2.4%	2.3%	2.5%	2.3%
	Ontario	0.0%	(0.1%)	(0.1%)	(0.2%)	(0.2%)	(0.2%)
	PJM	(0.2%)	(0.3%)	(0.3%)	(0.3%)	(0.3%)	(0.3%)
	TOTAL	0.0%	0.0%	(0.0%)	0.0%	0.0%	0.0%

Tables 4.3 through 4.5 below summarize the total impact on emissions production within each pool as a result of adding Cricket Valley to the NY Pool, assuming Indian Point Unit 2 is retired. Generally speaking, both NOx and SO2 production decrease across the region and within most pools, while Ontario shows a slight increase in both effluents in certain years.

Table 4.3 Total Annual NOx Production (Tons) by Pool

		2015	2016	2017	2018	2019	2020
Base Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	14,508	14,633	15,646	14,822	15,158	15,279
	NY Pool	27,315	27,841	28,502	27,948	28,884	28,855
	Ontario	2,100	2,132	2,102	2,103	2,079	2,098
	PJM	321,177	317,233	327,894	319,300	319,290	312,823
	TOTAL	365,100	361,839	374,144	364,173	365,411	359,055
Cricket Valley Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	14,355	14,428	15,428	14,611	14,933	15,005
	NY Pool	26,860	27,237	27,938	27,353	28,297	28,227
	Ontario	2,105	2,127	2,098	2,094	2,076	2,096
	PJM	320,892	316,526	327,054	318,806	318,570	312,073
	TOTAL	364,212	360,316	372,519	362,864	363,874	357,401
Increase (Decrease) (Tons)	NE Pool	(152)	(205)	(218)	(211)	(225)	(275)
	NY Pool	(455)	(604)	(564)	(595)	(588)	(628)
	Ontario	4	(5)	(4)	(9)	(3)	(2)
	PJM	(285)	(707)	(840)	(494)	(721)	(749)
	TOTAL	(889)	(1,522)	(1,625)	(1,309)	(1,537)	(1,654)
% Increase (Decrease)	NE Pool	(1.1%)	(1.4%)	(1.4%)	(1.4%)	(1.5%)	(1.8%)
	NY Pool	(1.7%)	(2.2%)	(2.0%)	(2.1%)	(2.0%)	(2.2%)
	Ontario	0.2%	(0.2%)	(0.2%)	(0.4%)	(0.2%)	(0.1%)
	PJM	(0.1%)	(0.2%)	(0.3%)	(0.2%)	(0.2%)	(0.2%)
	TOTAL	(0.2%)	(0.4%)	(0.4%)	(0.4%)	(0.4%)	(0.5%)

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Table 4.4 Total Annual SO2 Production (Tons) by Pool

		2015	2016	2017	2018	2019	2020
Base Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	75,733	76,545	83,994	76,769	77,866	79,001
	NY Pool	52,242	53,650	56,392	54,168	54,933	55,053
	Ontario	20,205	20,431	20,118	20,074	19,623	19,851
	PJM	1,811,431	1,761,710	1,799,974	1,747,856	1,735,674	1,678,548
	TOTAL	1,959,611	1,912,336	1,960,477	1,898,866	1,888,096	1,832,453
Cricket Valley Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	75,255	76,012	83,588	76,354	77,470	78,299
	NY Pool	51,597	52,472	55,821	53,399	54,151	53,972
	Ontario	20,248	20,430	20,137	20,093	19,686	19,925
	PJM	1,809,912	1,757,783	1,795,792	1,745,013	1,732,221	1,675,649
	TOTAL	1,957,013	1,906,697	1,955,337	1,894,858	1,883,529	1,827,846
Increase (Decrease) (Tons)	NE Pool	(478)	(533)	(406)	(415)	(396)	(702)
	NY Pool	(645)	(1,178)	(571)	(770)	(781)	(1,080)
	Ontario	44	(1)	19	19	64	74
	PJM	(1,519)	(3,926)	(4,182)	(2,842)	(3,453)	(2,899)
	TOTAL	(2,599)	(5,638)	(5,140)	(4,008)	(4,567)	(4,608)
% Increase (Decrease)	NE Pool	(0.6%)	(0.7%)	(0.5%)	(0.5%)	(0.5%)	(0.9%)
	NY Pool	(1.2%)	(2.2%)	(1.0%)	(1.4%)	(1.4%)	(2.0%)
	Ontario	0.2%	(0.0%)	0.1%	0.1%	0.3%	0.4%
	PJM	(0.1%)	(0.2%)	(0.2%)	(0.2%)	(0.2%)	(0.2%)
	TOTAL	(0.1%)	(0.3%)	(0.3%)	(0.2%)	(0.2%)	(0.3%)

Table 4.5 Total Annual CO2 Production (Tons) by Pool

		2015	2016	2017	2018	2019	2020
Base Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	43,595,529	43,536,684	45,441,151	44,765,693	45,263,246	46,082,928
	NY Pool	45,955,876	46,180,994	47,356,204	47,068,064	48,517,082	48,376,677
	Ontario	9,322,668	9,542,984	9,441,215	9,483,667	9,577,454	9,625,816
	PJM	427,776,195	425,569,214	433,779,988	428,523,674	429,133,279	420,652,703
	TOTAL	526,650,267	524,829,876	536,018,557	529,841,098	532,491,060	524,738,124
Cricket Valley Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	43,206,678	43,017,526	44,902,246	44,216,523	44,669,733	45,448,943
	NY Pool	46,511,440	47,162,600	48,508,642	48,225,565	49,828,127	49,567,089
	Ontario	9,344,530	9,477,979	9,370,594	9,357,031	9,479,169	9,535,539
	PJM	427,010,221	424,422,207	432,517,007	427,495,666	427,920,577	419,477,654
	TOTAL	526,072,869	524,080,313	535,298,490	529,294,785	531,897,606	524,029,226
Increase (Decrease) (Tons)	NE Pool	(388,851)	(519,159)	(538,905)	(549,170)	(593,513)	(633,986)
	NY Pool	555,564	981,607	1,152,439	1,157,501	1,311,045	1,190,412
	Ontario	21,862	(65,004)	(70,621)	(126,636)	(98,285)	(90,276)
	PJM	(765,973)	(1,147,007)	(1,262,980)	(1,028,009)	(1,212,702)	(1,175,048)
	TOTAL	(577,398)	(749,563)	(720,068)	(546,314)	(593,455)	(708,898)
% Increase (Decrease)	NE Pool	(0.9%)	(1.2%)	(1.2%)	(1.2%)	(1.3%)	(1.4%)
	NY Pool	1.2%	2.1%	2.4%	2.5%	2.7%	2.5%
	Ontario	0.2%	(0.7%)	(0.7%)	(1.3%)	(1.0%)	(0.9%)
	PJM	(0.2%)	(0.3%)	(0.3%)	(0.2%)	(0.3%)	(0.3%)
	TOTAL	(0.1%)	(0.1%)	(0.1%)	(0.1%)	(0.1%)	(0.1%)

Appendix C presents a comparison (Cost to Serve, Energy Production, Emissions Production) for the Base Case (without Cricket Valley), assuming Indian Point Unit 2 receives an operating license extension as compared against its retirement in 2013.

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

5 *Appendix A* – GE-MAPS™ Database Documentation (Eastern Interconnection (EI) Database, Revision 1.6, August 6, 2010)

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

GE Energy

GE-MAPS™ Database Documentation

Eastern Interconnection (EI) Database

Energy Applications & Systems Engineering (EA&SE)

Revision 1.6
August 6, 2010

Foreword

General Electric International, Inc prepared this document. Technical and commercial questions and any correspondence concerning this document should be referred to:

Thomas Vandor
GE Energy
1 River Road
Building 53, Room 302F
Schenectady, New York 12345
Phone: (518) 385-5783
Fax: (518) 385-5703
E-mail: thomas.vandor@ge.com

Revision History

Version	Date of Issue	Author(s)	Brief Description of Change(s)
1.0	2/22/2010	TAV	Original Issue
1.1	2/25/2010	TAV	Updated region map for Ontario, removed MRO from Table 2, editorials
1.2	3/15/2010	TAV	Updated load forecast data, demand-side management data, and added information about effects of regional energy efficiency programs (inserted new section 1.8). Added Appendices D, E, and F discussing the development of the load forecast, transmission data documentation & restrictions.
1.3	5/21/2010	TAV	Updated Appendix D for editorial content and caption labels of Tables & Figures. Updated Figure 1 caption and source reference text. Updated Appendix E.
1.4	6/25/2010	TAV	Updated Appendix D.
1.5	7/15/2010	TAV, SM	Added Appendix F containing informational list of applicable MAPS files associated with the database. Inserted new section 1.1 – "Introduction". Inserted new section 1.2 – "Data Table Subsets". Section 1.7.2.4: updated source(s) of unit emission rate data (Ventyx 2009 CEMS dataset) and added table of default emission rates for those units whose data are otherwise unavailable.
1.6	8/6/2010	TAV	Section 1.3: corrected list of EI NERC regions. Section 1.4.1: changed reference from 2008 ES&D to 2009 ES&D. Section 1.5: updated fuel price forecast vintages and charts and reorganized fuel types into individually numbered sub-sections. Section 1.10: replaced entire section with Transmission and Interchange discussion (previously section 1.11) – deleted section 1.11. Updated Appendix D. Updated Appendix E.

Legal Notices

General Electric International, Inc prepared this report. Neither GE, nor any person acting on behalf of GE:

1. Makes any warranty or representation, expressed or implied, with respect to the use of any information contained in this report, or that the use of any information, apparatus, method, or process disclosed in the report may not infringe privately owned rights.

2. Assumes any liabilities with respect to the use of or for damage resulting from the use of any information, apparatus, method, or process disclosed in this report.

Do Not Copy without written consent from GE Energy.
Copyright © 2010 GE Energy. All rights reserved.

Table of Contents

EASTERN INTERCONNECTION (EI) DATABASE 2010 BASE CASE ASSUMPTIONS 1

1.1 INTRODUCTION 1
1.2 DATA TABLE SUBSETS 1
1.3 REGION AND CONTROL AREAS WITHIN EI 2
1.4 LOAD FORECASTS, LOAD SHAPES 8
1.4.1 Load Forecasts 8
1.4.2 Load Shapes 8
1.5 FUEL PRICE ASSUMPTIONS 13
1.5.1 Natural Gas 13
1.5.2 Fuel Oil 13
1.5.3 Coal 14
1.5.4 Nuclear and Thermal Renewables 15
1.6 INFLATION & ESCALATION ASSUMPTIONS 15
1.7 GENERATING RESOURCES 15
1.7.1 Energy Velocity™ Data 15
1.7.2 Default Assumptions 16
1.7.3 Modeling of Gas Turbine Resources 18
1.7.4 Modeling of Combined Cycle Resources 18
1.7.5 Modeling of Base Load Resources 19
1.7.6 Modeling of Cogeneration / Private Network Units 19
1.7.7 Modeling of Wind Resources 19
1.7.8 Modeling of Hydro Resources 19
1.7.9 Modeling of Pumped Storage Hydro Resources 19
1.7.10 Ancillary Services Modeling 19
1.7.11 Firm Transfers 19
1.8 EXPANSION GENERATION FACILITIES 20
1.9 DEMAND-SIDE RESOURCES 20
1.10 TRANSMISSION & INTERCHANGE 20
1.10.1 Load Flow Models 21
1.10.2 Transmission Constraints 21

APPENDIX A: AVAILABILITY ASSUMPTIONS 22

APPENDIX B: NERC SUB-REGIONS WITHIN THE EI 23

APPENDIX C: KEY TO UNIT TYPES AND FUEL NAMES 33

APPENDIX D: LOAD FORECAST DEVELOPMENT 38

APPENDIX E: TRANSMISSION SYSTEM 42

SOURCES OF TRANSMISSION CONSTRAINT DATA 42

APPENDIX F: KEY MAPS FILES 43

Eastern Interconnection (EI) Database 2010 Base Case Assumptions

The purpose of this document is to describe the key underlying data and input assumptions for the GE-MAPS™ (MAPS) Eastern Interconnection (EI) database.

1.1 Introduction

Production costing is the mathematical simulation of the operation of an electric utility power system against an anticipated annual load. In order to accurately simulate the operation of an electric utility, comprehensive load and system models must be created. Consequently, prior to running MAPS, information describing the power system and the load must be entered.

Information that is used to create the utility power system model is entered through the Master Input File (MIF). The MAPS User's Manual fully describes the MIF and provides a general explanation of the MIF data entry process. For more information outlining specific MIF data entry procedures and common data items, refer to the MAPS User's Manual.

1.2 Data Table Subsets

The MIF is a set of data tables that is organized by subject into logical subsets. Each data table contains one or more data fields into which is entered information that assigns a value to a specific program variable. Each of the MIF subsets is a group of data tables that describes one aspect of the system model. For example, information describing the thermal generators are entered under one subset heading, information describing maintenance scheduling another, etc.

The following is a list of the MIF subsets and a brief description of the data they contain or the program direction they provide.

- General Study Data – Study, company, and geographic identification, general financial data.
- Load Models – Information to create a study load model from raw Edison Electric Institute (EEI) load data.
- Non-Thermal Resources – Data to model resources such as run-of-river and pondage hydro-generators, and firm energy sales and purchases.
- Thermal Units – Information describing the thermal generators that are modeled by the program.
- Energy Storage Units – Information describing the energy-storage units – such as pumped storage hydro – that are modeled by the program.
- Unit Commitment/Dispatch – Information to determine the order in which the generating units will be committed and dispatched.
- MWFLOW (Transmission Model) – Directs the program in using the optional transmission system load flow model instead of the transportation model.
- Maintenance Scheduling – This information creates a maintenance schedule for each generating unit.

- Transfer Limits – Transmission system transportation model transfer limits.
- Operating Reserve – Data for calculating the operating reserve requirements.
- External Contracts – Pricing determination for inter-utility power sales and purchases.
- MARGIN – Data and settings for an auxiliary program that calculates marginal costs.
- Output Reports – Directs the program to print various user-selected output reports.
- Customer Specific Variables – Program variables and options developed specifically for the various utility customers.

1.3 Region and Control Areas Within EI

In 2008, the GE Energy Applications and Systems Engineering Department (EA&SE) began migrating its MAPS database source to Ventyx Global Energy Decision's Energy Velocity™ Suite (EV).

Pursuant to the Federal Power Act the North American Electric Reliability Corporation (NERC) was certified in 2006 as the Electric Reliability Organization of the United States and is overseen by the US Federal Energy Regulatory Commission (FERC). Similarly, the provincial governments oversee NERC in Canada. NERC is tasked with ensuring the reliability of the North American bulk power system. The power systems are divided into five interconnections and nine regional areas under NERC's organization as shown in Figure 1. Six of the nine regions comprise the EI and are listed below:

- FRCC – Florida Reliability Coordinating Council
- MRO – Midwest Reliability Organization
- NPCC – Northeast Power Coordinating Council
- RFC – Reliability First Corporation
- SERC – SERC Reliability Corporation
- SPP – Southwest Power Pool

The Eastern Interconnection is one of the major electrical interconnections of North America. While electrically independent of its neighboring interconnections, the EI is nevertheless connected to the neighboring Quebec, Western and Texas interconnections either through asynchronous high voltage direct current (HVDC) ties and/or through variable frequency transformers (VFT). The EI is comprised mostly of the eastern and mid-western portions of the United States and Canada as shown in Figure 1 below.

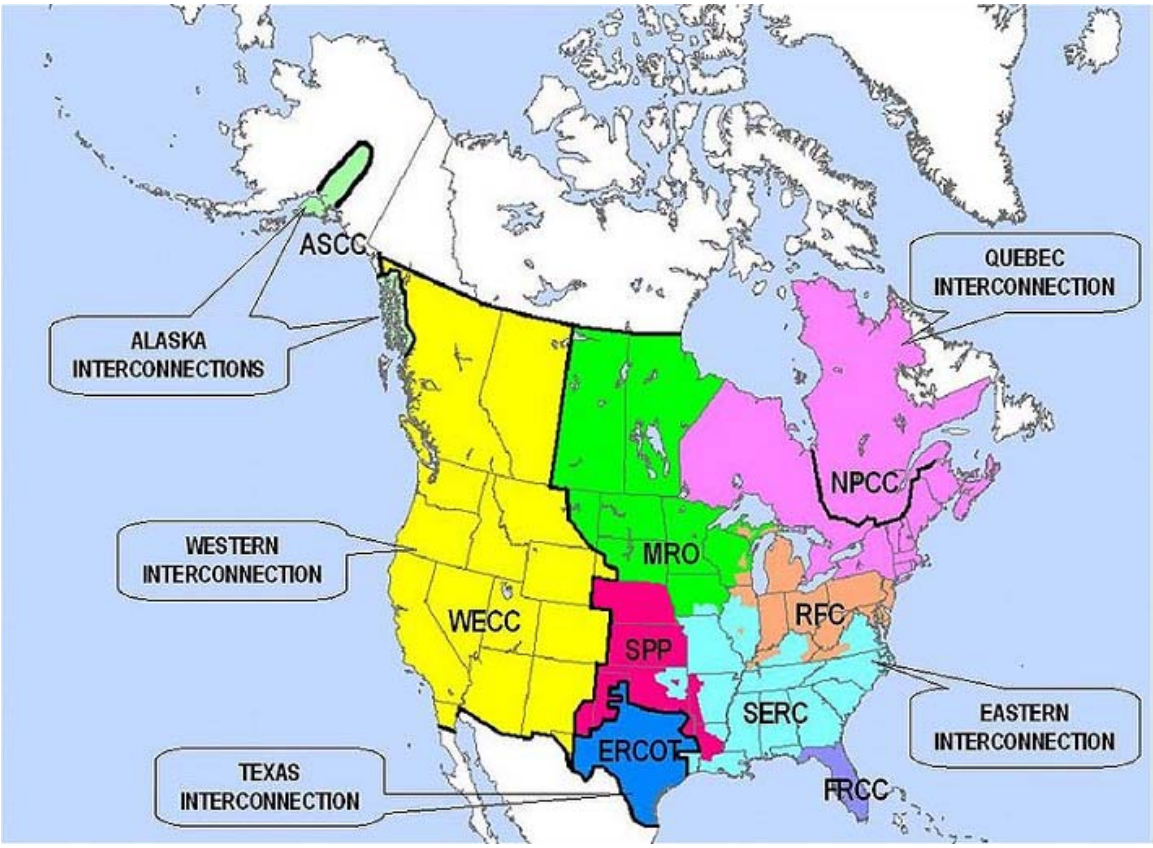
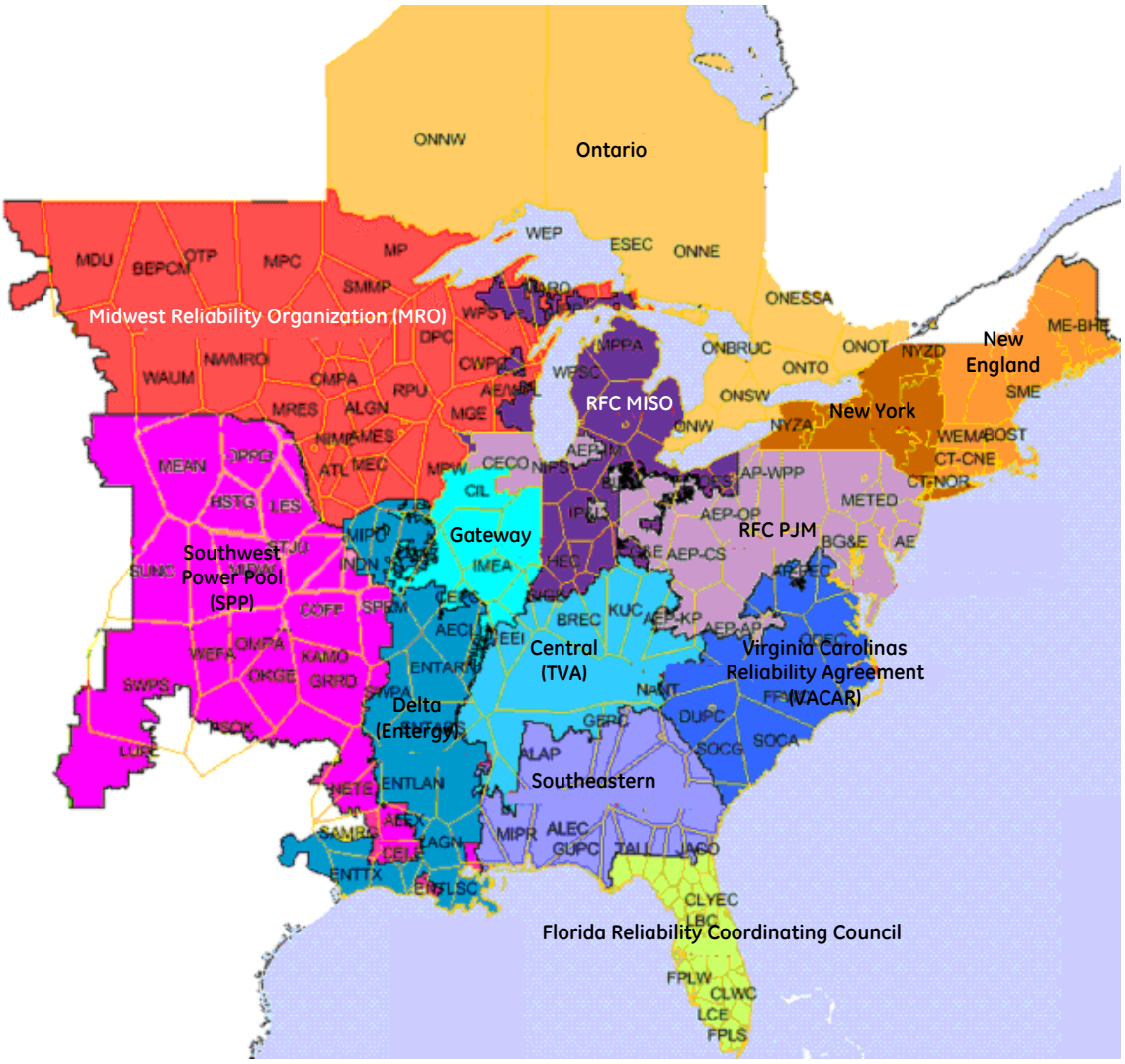


Image Source: http://en.wikipedia.org/wiki/Eastern_Interconnection permission to reproduce granted under http://en.wikipedia.org/wiki/Wikipedia:Text_of_Creative_Commons_Attribution-ShareAlike_3.0_Unported_License

Figure 1 - Electrical Interconnections and NERC Regions of North America

Figure 2 illustrates the EI NERC sub-regions and transmission zones. Additional figures depicting each individual NERC sub-region are provided in Appendix B.



Source: GE Energy and Ventyx Energy Velocity

Figure 2 - EI NERC Sub-regions and Transmission Zones

The current MAPS EI database reflects approximately 245 Market/Load areas. The areas modeled in the EI database are listed in Table 1 below.

Table 1 - MAPS EI Pools and Areas

POOLNAME	AREA NAME	AREA LONG NAME
Entergy	AECI	Associated Electric Cooperative Inc.
	CEPC	Central Electric Power Cooperative
	ENTARN	Entergy Arkansas North
	ENTARS	Entergy Arkansas South
	ENTLAN	Entergy Louisiana North
	ENTLSC	Entergy Louisiana South Central
	ENTLSE	Entergy Louisiana Southeast
	ENTLSW	Entergy Louisiana Southwest
	ENTMS	Entergy Mississippi
	ENTTX	Entergy Texas
	KAMO	KAMO Electric Coop.
	LAGN	Louisiana Generating/Cajun Electric
FRCC	CFLE	Central Florida Electric Cooperative
	CLWC	Clewiston (City of)
	CLWU	Lake Worth Utilities (City of)
	CLYEC	Clay Electric Cooperative
	FOPC	Fort Pierce Utilities Authority
	FPCD	Progress Energy Florida - Deland
	FPCLW	Progress Energy Florida - Lake Wales
	FPCM	Progress Energy Florida - Monticello
	FPCO	Progress Energy Florida - Ocala
	FPCS	Progress Energy Florida - St. Petersburg
	FPLE	Florida Power & Light - East
	FPLN	Florida Power & Light - North
	FPLS	Florida Power & Light - South
	FPLSE	Florida Power & Light - South East
	FPLW	Florida Power & Light - West
	GAMW	Gainesville Regional Utilities
	GLDEC	Glades Electric Cooperative
	GRNCS	Green Cove Springs
	HSTM	Homestead (City of)
	JACO	Jacksonville Electric Authority
	JCKLB	Jacksonville Beach
	KEYW	Key West Utility Board
	KUAM	Kissimmee Utility Authority
	LALW	Lakeland Dept. of Electric & Water Utilities
	LBC	Leesburg (City of)
	LCE	Lee County Electric Cooperative
	NSBM	New Smyrna Beach Utilities Commision
	OEU	Ocala Electric Utility
	OUC	Orlando Utilities Commission
	PREC	Peace River Electric Cooperative
	RKDE	Rockland Electric Company
	SCLE	St. Cloud Electric Utilities
	SEC	Sumter Electric Cooperative
	SECI	Seminole Electric Cooperative Inc.
	STE	Starke Electric System (City of)
	SWVE	Suwannee Valley Electric Cooperative
	TAEC	Tampa Electric Company
	TALL	Tallahassee Electric Dept. (City of)
	TCE	Tri-County Electric Coop (FL)
ONT	ONBRUC	Ontario-Bruce
	ONE	Ontario-East
	ONESSA	Ontario-ESSA
	ONNE	Ontario-Northeast
	ONNI	Ontario-Niagara
	ONNW	Ontario-Northwest
	ONOT	Ontario-Ottawa
	ONSW	Ontario-Southwest
	ONTO	Ontario-Toronto
	ONW	Ontario-West
RFC	AE	Atlantic Electric
	AEP-AP	Appalachian Power Company (AEP)
	AEP-CS	Columbus Southern Power Company (AEP)
	AEP-IM	Indiana Michigan Power Company (AEP)
	AEP-KP	Kentucky Power Company (AEP)
	AEP-OP	Ohio Power Company (AEP)
	AP-MON	Monongahela Power Company (APS)
	AP-PEC	Potomac Edison Company (APS)
	AP-WPP	West Penn Power Company (APS)
	BG&E	Baltimore Gas & Electric Company
	BUCK	Buckeye Power Inc.
	CECO	Commonwealth Edison Co.
	CG&E	Duke Energy Ohio/Kentucky
	COL	Lansing (City of)
	CONS	Consumers Energy
	DECO	Detroit Edison Company
	DLCO	Duquesne Light Company
	DP&L	Delmarva Power & Light Company
	DPL	Dayton Power & Light Co.
	ESEC	Edison Sault Electric Company
	FE-CEI	Cleveland Electric Illuminating Co. (First Energy)
	FE-OES	Ohio Edison Company (First Energy)
	FE-PEN	Pennsylvania Power Company (First Energy)
	FE-TE	Toledo Edison Company (First Energy)
	HBPW	Holland Board of Public Works (City of)
	HEC	Hoosier Energy Rural Elec.
	IMEA	Illinois Municipal Electric Agency
	IMPA	Indiana Municipal Power Agency
	IP&L	Indianapolis Power & Light
	JCP&L	Jersey Central Power & Light Company
	METED	Metropolitan Edison Company
	MPPA	Michigan Public Power Agency
	NIPS	Northern Indiana Public Service
	OVEC	Ohio Valley Electric Corp.
	PE	PECO Energy Company
	PENLEC	Pennsylvania Electric Company
	PEPCO	Potomac Electric Power Company
	PP&L	Pennsylvania Power & Light Company
	PSE&G	Public Service Electric & Gas Company
	PSI	Duke Energy Indiana
	SIGE	Southern Indiana Gas & Electric

Table 1 - MAPS EI Pools and Areas

POOLNAME	AREA NAME	AREA LONG NAME
FRCC (Cont.)	TLQE	Talquin Electric Cooperative
	VEBM	Vero Beach Municipal Utilities
	WTCR	Withlacoochee River Electric Cooperative
Gateway	CIL	Central Illinois Light Co.
	CIPS	Central Illinois Public Service (AmerenCIPS)
	CWL	Columbia Missouri Water and Light Department
	CWLP	Springfield Illinois - City Water Light & Power
	EEI	Electric Energy Inc.
	IP	Illinois Power
	SIPC	Southern Illinois Power Co-operative
	UE	Union Electric Company (AmerenUE)
ISO NE	BOST	ISNE - Boston
	CT-CNE	ISNE - Connecticut - Central-Northeast
	CT-NOR	ISNE - Connecticut - Norwalk
	CT-SW	ISNE - Connecticut - Southwest
	MA-CNE	ISNE - Massachusetts - Central-Northeast
	ME-BHE	ISNE - Maine - Bangor Hydro Electric
	ME-CMP	ISNE - Maine - Central
	NH	ISNE - New Hampshire
	RI	ISNE - Rhode Island
	SEMA	ISNE - Massachusetts - Southeast
	SME	ISNE - Maine - Southwest
	VT	ISNE - Vermont
	WEMA	ISNE - Massachusetts - Western
MRO	AE/WPL	Alliant East - Wisconsin Power and Light Company
	ALGN	Algona Municipal Utilities
	AMES	Ames Municipal Electric System
	ATL	Atlantic Municipal Utilities
	AW/IPL	Alliant West - Interstate Power & Light
	BEPCM	Basin Electric Power Coop MAPP
	CBPC	Corn Belt Power Coop
	CDFL	Cedar Falls Utilities
	CIPCO	Central Iowa Power Coop
	CMPA	Central Minnesota Municipal Power Agency
	CWPC	Consolidated Water Power Co
	DPC	Dairyland Power Cooperative (GSE)
	GRE	Great River Energy
	HCPD	Heartland Consumers Power District
	HRLMV	Harlan Municipal Utilities
	HUC	Hutchinson Utilities Commission
	MARQ	Marquette Michigan Board of Light and Power
	MDU	Montana-Dakota Utilities Co.
	MEC	Midamerican Energy Co.
	MGE	Madison Gas and Electric Company
	MP	Minnesota Power and Light Company
	MPC	Minnkota Power Cooperative Inc.
	MPU	Manitowoc Wisconsin Public Utilities
	MPW	Muscatine Power & Water
	MRES	Missouri River Energy Services
	NIME	North Iowa Municipal Electric Coop Assoc
	NIPC	Northwest Iowa Power Cooperative
	NSP	Northern States Power Company

POOLNAME	AREA NAME	AREA LONG NAME
RFC (Cont.)	UGIC	UGI Corporation
	WEP	Wisconsin Electric Power Company
	WPSC	Wolverine Power Supply Coop
Southern	ALAP	Alabama Power Company
	ALEC	Alabama Electric Cooperative Inc.
	CCPC	Crisp County Power Commission
	GEPC	Georgia Power Company
	GUPC	Gulf Power Company
	MEAG	Municipal Electric Authority of Georgia
	MIPR	Mississippi Power Company
	OPC	Oglethorpe Power Corporation
	SAEP	Savannah Electric and Power Company
	SEPA	Southeastern Power Administration
	SMEPA	South Mississippi Electric Power Association
SPP (North)	COFF	Coffeyville (City of)
	EMDE	Empire District Electric Co.
	HSTG	Hastings Utilities (NE)
	INDN	City Power & Light Independence
	KACP	Kansas City Power & Light Co.
	KACY	Board of Public Utilities Kansas City Kansas
	LES	Lincoln Electric System
	MEAN	Municipal Energy Agency of Nebraska
	MIDW	Midwest Energy Inc.
	MIPU	Missouri Public Service Company
	NPPD	Nebraska Public Power District
	OPPD	Omaha Public Power District
	SPRM	City Utilities Springfield
	STJO	St. Joseph Power & Light Co.
	SUNC	Sunflower Electric Power Corp.
	WERE	Westar Energy/Western Resources
	WPEK	Kansas Electric Network
SPP (South)	ALEX	Alexandria (City of)
	CELE	Central Louisiana Electric Co. Inc.
	GRRD	Grand River Dam Authority
	LAFA	Lafayette (City of)
	LEPA	Louisiana Energy and Power Authority
	LUPL	Lubbock (City of)
	NETE	Northeast Texas Electric Coop.
	OKGE	Oklahoma Gas & Electric Company
	OMPA	Oklahoma Municipal Power Authority
	PSOK	Public Service Company of Oklahoma
	SAMRG	Sam Rayburn G & T Inc.
	SIKE	Sikeston (City of)
	SOEP	Southwestern Electric Power Company
	SWPA	Southwestern Power Administration
	SWPS	Southwestern Public Service Company
	WEFA	Western Farmers Electric Cooperative
TVA	BREC	Big Rivers Electric Corp
	EKPC	East Kentucky Power Coop.
	HMP&L	Henderson Municipal Power & Light
	KUC	Kentucky Utilities Co. (LG&E)
	LG&E	Louisville Gas & Electric (LG&E)

Table 1 - MAPS EI Pools and Areas

POOLNAME	AREA NAME	AREA LONG NAME
MRO (Cont.)	NULM	New Ulm Public Utilities
	NWMRO	NorthWestern Energy - MRO
	OTP	Otter Tail Power Company
	PLLA	Pella (City of)
	RPU	Rochester Public Utilities
	SMMP	Southern MN Municipal Power Agency
	UPP	Upper Peninsula Power Company
	WAUM	WAPA - Upper Missouri (east)
	WLMR	Willmar Municipal Utilities Commission
	WPPI	Wisconsin Public Power Inc. MAPP
	WPPIM	Wisconsin Public Power Inc. MAIN
	WPS	Wisconsin Public Service Corporation
	WVY	Waverly Light and Power
NY	NYZA	New York Zone A - West
	NYZB	New York Zone B - Genessee
	NYZC	New York Zone C - Central
	NYZD	New York Zone D - North
	NYZE	New York Zone E - Mohawk Valley
	NYZF	New York Zone F - Capital
	NYZG	New York Zone G - Hudson Valley
	NYZH	New York Zone H - Millwood
	NYZI	New York Zone I - Dunwoodie
	NYZJ	New York Zone J - NY City
	NYZK	New York Zone K - L Island

POOLNAME	AREA NAME	AREA LONG NAME
TVA (Cont.)	TAPO	Tapoco Inc.
	TVA	Tennessee Valley Authority
VACAR	CPLE	Progress Energy Carolinas East
	CPLW	Progress Energy Carolinas West
	DUPC	Duke Energy Carolinas
	FPWC	Fayetteville Public Works Commission
	LHPC	Lockhart Power Company
	NANT	Nantahala Power & Light Company
	ODEC	Old Dominion Electric Cooperative
	SOCA	Santee Cooper
	SOCG	South Carolina Electric & Gas Company
	VIEP	Virginia Power Company
	YADI	Yadkin Inc.

1.4 Load Forecasts, Load Shapes

1.4.1 Load Forecasts

In general, the EI Database peak load forecast is based upon data from the North American Electric Reliability Council (NERC) Electricity Supply and Demand (ES&D) database (November 2009 release date), the NERC 2009 Long-Term Reliability Assessment, the NERC 2008/2009 Winter Reliability Assessment, NERC 2009 Summer Reliability Assessment, and ISO/RTO data where available. The year 2009 peak demand and net energy for load data is from the "2009 NERC ES&D Forecast" issued in November 2009.

Typically, the 2009 NERC ES&D load forecast would be implemented as published, however, due to the economic downturn that has occurred since the data were compiled, that forecast is more optimistic than currently expected, especially in the next few years. Therefore, EA&SE has developed adjustments to this forecast based on the historical correlation of peak load to U.S. Gross Domestic Product (GDP). The analyst should review load forecast assumptions greater detail prior to implementing any one particular forecast.

Table 2 details the EI load forecast implemented in MAPS through 2020 by NERC sub-region, and Appendix D further details the approach used for developing the US load forecast.

Table 2 - EI Peak Load Forecast by NERC Sub-region (MW)

NERC Sub-region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
FRCC	44,095	44,456	45,553	46,383	47,016	47,625	48,191	48,771	49,615	50,629	51,671
MRO	40,735	41,236	41,959	42,554	42,949	43,294	43,629	43,934	44,354	44,858	45,375
NEP	25,719	25,962	26,444	26,769	27,036	27,245	27,404	27,554	27,732	27,946	28,165
NYP	31,625	31,773	32,004	32,168	32,326	32,426	32,599	32,756	32,989	33,269	33,556
RFC	166,964	170,041	174,353	176,644	178,011	179,075	180,031	181,017	182,154	183,520	184,923
Central (formerly TVA)	42,331	42,754	43,481	44,469	45,059	45,294	45,660	45,970	46,454	47,035	47,632
Delta (formerly Entergy)	27,411	28,023	28,515	28,980	29,407	29,609	29,797	29,982	30,216	30,496	30,784
Gateway	19,824	20,038	20,206	20,308	20,375	20,474	20,560	20,657	20,774	20,914	21,058
Southeastern (Southern)	48,499	49,476	50,846	51,945	52,754	53,397	53,984	54,644	55,283	56,052	56,841
VAC	62,832	63,715	65,413	66,595	67,400	68,073	68,702	69,362	70,218	71,247	72,304
SPP	44,095	44,456	45,553	46,383	47,016	47,625	48,191	48,771	49,615	50,629	51,671
Ontario	23,998	23,839	23,383	22,937	22,778	22,470	22,503	22,387	22,346	22,305	22,264

1.4.2 Load Shapes

The modeling of load is based on load shapes from FERC Form 714 data, which were extracted from EV and adjusted to be consistent with forecasts of peak and energy. The load shapes for each EI zone are calculated, based on the following indirect average load shape methodology. The indirect average methodology is used to reduce several years of recent data without reducing the peaks or increasing the valleys of the load shape – an effect which may occur when a direct average methodology is used. The following illustrative example describes the process of indirect averaging at the monthly level, although this methodology is also applied at the hourly level:

Step 1 - For each month interval (12 month intervals per calendar year) within a given year, the monthly peaks are expressed as a "per unitized" (PU) ratio of the annual peak. For the EI Database, this process was performed for each year over the 2004-2006 period.

STEP 1			
MONTH	YEAR	AREA PEAK LOAD	PEAK LOAD PU VALUES
1	2004	12,552	0.643
2	2004	12,519	0.641
3	2004	14,008	0.718
4	2004	16,763	0.859
5	2004	17,595	0.901
6	2004	15,975	0.818
7	2004	18,905	0.968
8	2004	19,256	0.986
9	2004	19,521	**1.000**
10	2004	14,704	0.753
11	2004	13,573	0.695
12	2004	13,767	0.705
1	2005	13,166	0.637
2	2005	12,816	0.620
3	2005	12,907	0.625
4	2005	12,694	0.614
5	2005	15,801	0.765
6	2005	15,611	0.755
7	2005	18,722	0.906
8	2005	20,664	**1.000**
9	2005	19,888	0.962
10	2005	18,066	0.874
11	2005	15,517	0.751
12	2005	13,956	0.675
1	2006	12,949	0.598
2	2006	13,143	0.607
3	2006	12,813	0.592
4	2006	12,716	0.588
5	2006	14,918	0.689
6	2006	17,776	0.821
7	2006	20,139	0.931
8	2006	21,642	**1.000**
9	2006	20,853	0.964
10	2006	17,075	0.789
11	2006	13,909	0.643
12	2006	14,943	0.690

Step 2 - For each of the 12 month intervals, the "per unitized" ratios above are summed over the three-year period. The resulting 12 values are then rank-ordered from highest to lowest value.

STEP 2 A

MONTH	SUM_PU
1	1.878
2	1.869
3	1.934
4	2.061
5	2.355
6	2.395
7	2.805
8	2.986
9	2.926
10	2.416
11	2.089
12	2.071

STEP 2 B

RANK	MONTH	SUM_PU
1	8	2.986
2	9	2.926
3	7	2.805
4	10	2.416
5	6	2.395
6	5	2.355
7	11	2.089
8	12	2.071
9	4	2.061
10	3	1.934
11	1	1.878
12	2	1.869

Step 3 - Over the 2004 – 2006 period, the 12 "per-unitized" ratios are first rank-ordered from highest to lowest value within each year, and then rank-ordered across all three years and divided into 12 groups of three ratios.

STEP 3 A				STEP 3 B			
RANK	YEAR	MONTH	PU LOAD	RANK	YEAR	MONTH	LF
1	2004	9	1.000	1	2004	9	1.000
2	2004	8	0.986	1	2005	8	1.000
3	2004	7	0.968	1	2006	8	1.000
4	2004	5	0.901	2	2004	8	0.986
5	2004	4	0.859	2	2005	9	0.962
6	2004	6	0.818	2	2006	9	0.964
7	2004	10	0.753	3	2004	7	0.968
8	2004	3	0.718	3	2005	7	0.906
9	2004	12	0.705	3	2006	7	0.931
10	2004	11	0.695	4	2004	5	0.901
11	2004	1	0.643	4	2005	10	0.874
12	2004	2	0.641	4	2006	6	0.821
1	2005	8	1.000	5	2004	4	0.859
2	2005	9	0.962	5	2005	5	0.765
3	2005	7	0.906	5	2006	10	0.789
4	2005	10	0.874	6	2004	6	0.818
5	2005	5	0.765	6	2005	6	0.755
6	2005	6	0.755	6	2006	12	0.690
7	2005	11	0.751	7	2004	10	0.753
8	2005	12	0.675	7	2005	11	0.751
9	2005	1	0.637	7	2006	5	0.689
10	2005	3	0.625	8	2004	3	0.718
11	2005	2	0.620	8	2005	12	0.675
12	2005	4	0.614	8	2006	11	0.643
1	2006	8	1.000	9	2004	12	0.705
2	2006	9	0.964	9	2005	1	0.637
3	2006	7	0.931	9	2006	2	0.607
4	2006	6	0.821	10	2004	11	0.695
5	2006	10	0.789	10	2005	3	0.625
6	2006	12	0.690	10	2006	1	0.598
7	2006	5	0.689	11	2004	1	0.643
8	2006	11	0.643	11	2005	2	0.620
9	2006	2	0.607	11	2006	3	0.592
10	2006	1	0.598	12	2004	2	0.641
11	2006	3	0.592	12	2005	4	0.614
12	2006	4	0.588	12	2006	4	0.588

Step 4 – For each of the 12 groups of three ratios, an average of the three ratios is calculated, and the resulting values are then re-sorted into chronological order (Month Interval 1, 2, 3, etc.).

STEP 4 A

RANK	MONTH	INDIRECT AVERAGED PU
1	8	1.000
2	9	0.971
3	7	0.935
4	10	0.866
5	6	0.804
6	5	0.755
7	11	0.731
8	12	0.679
9	4	0.650
10	3	0.639
11	1	0.618
12	2	0.614

STEP 4 B SORTED MONTHS

RANK	MONTH	INDIRECT AVERAGED PU
11	JAN	0.618
12	FEB	0.614
10	MAR	0.639
9	APR	0.650
6	MAY	0.755
5	JUN	0.804
3	JUL	0.935
1	AUG	1.000
2	SEP	0.971
4	OCT	0.866
7	NOV	0.731
8	DEC	0.679

Step 5 - The resulting chronological "indirect" average load ratios are then applied to the forecasted annual peak load, to estimate each of the monthly intervals.

STEP 5

MONTH	INDIRECT AVERAGE PU LOAD	INDIRECT AVERAGE LOAD
1	0.62	13,383.8
2	0.61	13,296.7
3	0.64	13,838.2
4	0.65	14,065.0
5	0.75	16,334.5
6	0.80	17,402.7
7	0.94	20,235.4
8	1.00	21,642.0
9	0.97	21,010.2
10	0.87	18,734.6
11	0.73	15,823.7
12	0.68	14,685.2

This method assumes that each year of historical data will contribute equally to the final load shape. If one or more years are determined to be abnormal (due to some weather, economic, or social influence), a series of non-equal annual weightings (which sum to 1.0) may be applied to each per-unitized ratio in Step 1. In the above illustrative example, if all three years are assumed to equally represent loads during this period, each year implicitly has a weighting of 0.333 (1/3 = 0.333). However, if 2005 is assumed to be an abnormal year due to weather events (such as hurricanes), it may be necessary to apply a lower weight to 2005 and higher but equal weights to the remaining years, such as 0.10 for 2005 and 0.45 for the other years (0.45 + 0.10 + 0.45 = 1.0).

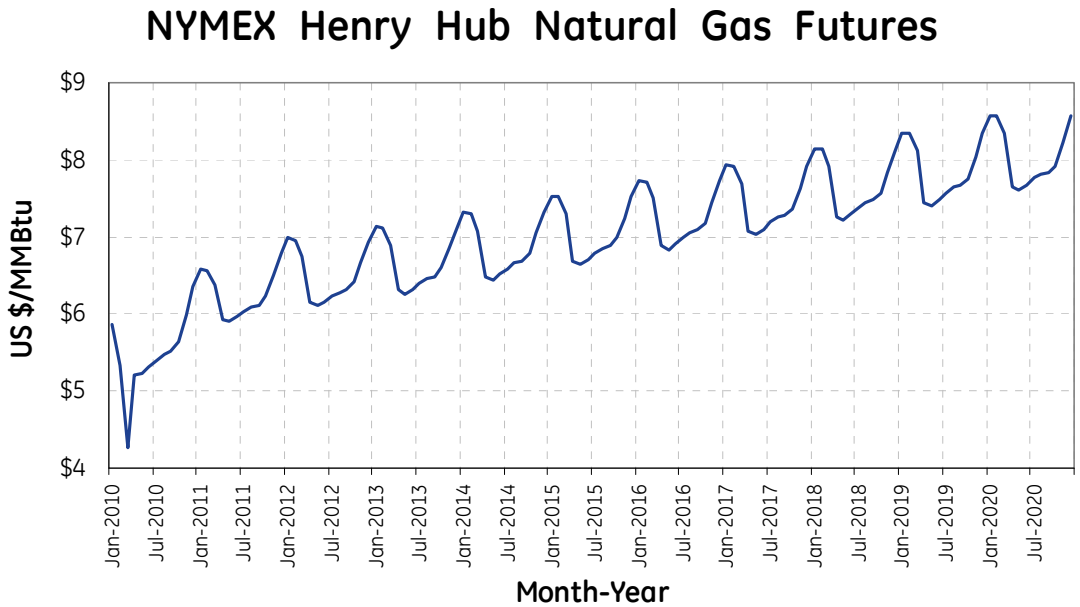
1.5 Fuel Price Assumptions

Fuel price assumptions for the EI Database were obtained from forecasts within the EV dataset.

1.5.1 Natural Gas

Natural gas price forecast assumptions are based upon the NYMEX futures contracts for Henry Hub (HH) natural gas. Daily closing prices from November 2009 to April 2010 were averaged by delivery month to determine the default natural gas price forecasts for those delivery months. Prices for natural gas at 52 nodes across the EI database were estimated by performing an historical analysis of basis differentials between these nodes and historical HH prices, including Transco Zone 6 Non-NY.

Figure 3 illustrates the natural gas price assumptions in the EI MAPS database.



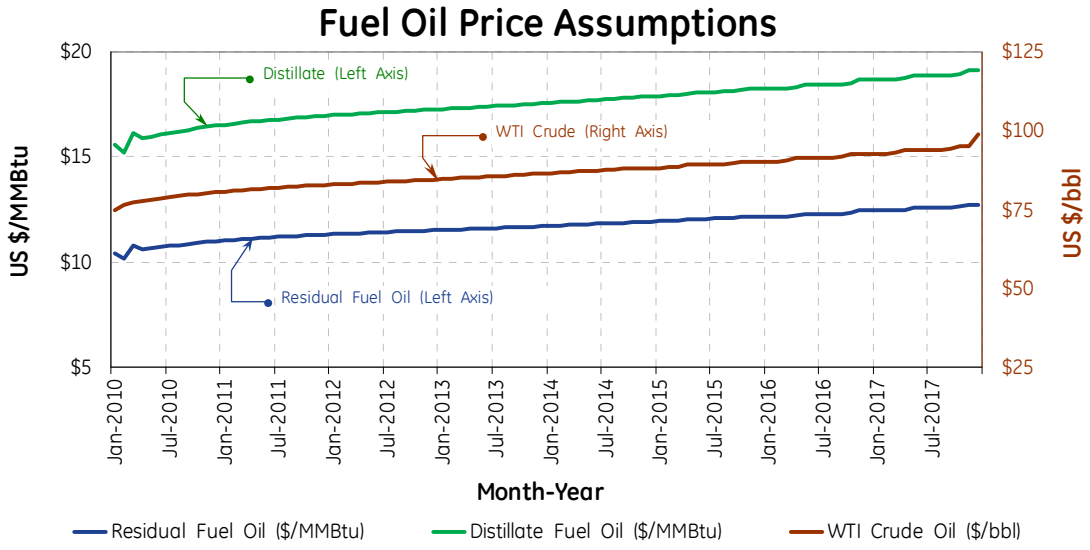
Source: Ventyx Energy Velocity NYMEX ClearPort database, average trades Nov '09 - Apr '10.

Figure 3 - NYMEX Henry Hub Natural Gas Future Prices

1.5.2 Fuel Oil

Oil price forecast assumptions are based upon the NYMEX futures contracts for West Texas Intermediate (WTI) crude oil. Daily closing prices from November 2009 to April 2010 were averaged by delivery month to determine the default oil price forecasts for those delivery months.

The crude oil price projections in $/bbl are converted to #6 residual fuel oil (1% sulfur content) and #2 distillate fuel oil price projections in $/MMBtu assuming heat contents of 6.287 MMBtu/bbl and 5.825 MMBtu/bbl, respectively. Figure 4 illustrates the fuel oil price assumptions in the EI MAPS database.

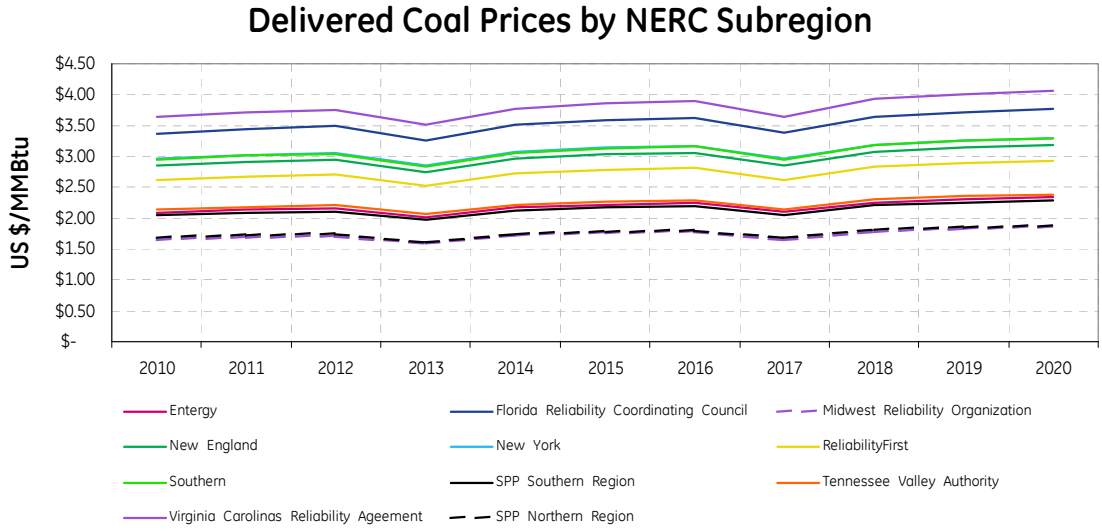


Source: NYMEX WTI Crude Oil Futures: Ventyx Energy Velocity, average trades Nov '09 - Apr '10. Residual and Distillate projections based on assumed 6.287 and 5.825 MMBtu/bbl, respectively.

Figure 4 - Fuel Oil Price Assumptions

1.5.3 Coal

For future years, coal prices by grade are specified for each NERC sub-region modeled in the EI database, based upon EV coal price projections from March 2010. The EV coal price projections (by grade, by region) are used to calculate an average price ($/MMBtu) for each sub-region within the EI database. Figure 5 illustrates lists the coal prices reflected in the EI database.



Source: Ventyx Energy Velocity, Mar '09.

Figure 5 - Delivered Coal Prices

1.5.4 Nuclear and Thermal Renewables

Nuclear fuel prices are assumed to be $0.56/MMBtu, and a default fuel cost assumption for renewable-based thermal generation technologies is $0.01/MMBtu. (Note: renewable fuel prices are often specific to the technology and geographic location of the facility. For this reason, a default fuel assumption is employed and plant-specific variable costs are reflected in the Variable O&M charges).

1.6 Inflation & Escalation Assumptions

Non-proprietary inflation and escalation assumptions are based on EA&SE review of general planning assumptions for financial analysis. These annual factors are embedded within MAPS using various Inflation Patterns or profiles. The current general inflation assumption is 2.0% annually in all years.

1.7 Generating Resources

1.7.1 Energy Velocity™ Data

The data for generating resources in the MAPS EI database was obtained from the EV database, extracted in January 2010. Within the EI database, generating resources are represented at the unit level, based on individual unit cost, operations and performance data from EV. Individual units or facilities with ratings less than 20 MW are generally aggregated into a larger, representative facility located within the geographical area.

For those existing generating resources where plant-specific data (cost, performance, operations, etc.) was publicly available, this data was included.

In the absence of plant-specific data, default assumptions were made using publicly available sources[1] and/or EA&SE estimates. For example, EA&SE applies generating plant operation and performance curves (developed by GE Energy's Engineering group) for each technology modeled to estimate the power points and the incremental heat rates associated with each power point. Additional operational performance characteristics and assumptions are developed based upon various studies and analyses prepared by EA&SE:

- Minimum Down Time: estimates based upon analysis of actual historical
- Minimum Up Time: not currently modeled in MAPS
- Must Run: currently applies to all gas turbine, conventional hydro, and "RMR" or reliability
- Start-Up Costs: assumptions are based on GE Contract Services estimates of median costs amortizing the inspection and maintenance costs over the number of operating hours or startups that would trigger inspections and maintenance
- Planned and Forced Outage Rates: based on EA&SE estimates using the NERC Generating Availability Data System (GADS)

[1] Wood, Wollenberg. "Power Generation, Operation, and Control", 1996.

1.7.2 Default Assumptions

1.7.2.1 Cost and Performance

The default assumptions for generating resources are organized by technology and fuel (example: Steam Turbine-Coal, Combustion Turbine-Oil, Combined Cycle-Gas, etc.), by Commercial Operation Date range (example: plants entering service before 1995, plants entering service after 1995), and by size (MW) of plant (example: Steam Turbine-Coal plants below 50 MW, from 50 MW to 199.9 MW, 200 MW to 399.9 MW, 400 MW to 599.9 MW, and over 600 MW). For each generating resource type, vintage, and size, a minimum of two and a maximum of five Power Points or capacity states are defined, and the associated Average Heat Rate at each Power Point is specified. These assumptions are based on publicly available sources2 and/or EA&SE estimates.

For each generating resource type and size, start up costs and the number of hours to convert the Start Up Costs dollars into $/MWh for commitment are defined, based on the Continuous Emissions Monitoring Systems (CEMS) experience-based number of hours per startup for a unit in that size range. If omitted, the default is the Minimum Down Time in hours. These assumptions are based on EA&SE estimates.

The MAPS program allows the user to specify a "Bid Adder", an amount that will be added to a unit's calculated costs based on fuel cost, heat rate, O&M and emissions. This adder is often used to reflect the unit's start-up cost in the dispatch pricing. To that end an analysis was performed to tie the start-up costs to the unit type, size and typical hours on line, and a straight-line approximation was made to eliminate discontinuities. The adder is then calculated as:

Bid Adder = Max Capacity * Slope + Intercept.

This bid adder is then applied across the entire unit. As an option, the program will also allow the user to specify bid adders on each section of a unit. The values currently populated in MAPS are based on EA&SE estimates and assumptions.

Variable Operation & Maintenance (“VOM”) costs, Fixed Operation & Maintenance (“FOM”) costs, and other Operation & Maintenance (“O&M”) costs along with an association inflation pattern for each component may also be entered. O&M costs assumed in the EI database are based upon analysis completed by EA&SE (September 23, 1999). For coal, oil and natural gas-fired boilers, a three-year average was calculated using Platts RDI data for both VOM and FOM costs. For combustion turbine and combined cycle technologies, the RDI data was supplemented with internal estimates for both VOM and FOM developed by GE Energy’s Engineering group.

Various penalty factors may also be entered as a per-unit multiplier of the unit costs. Penalty Factors can be used to adjust the commitment order of the thermal units. Penalty factors are sometimes used to effectively make or force some high-cost units into a “Must Run” status. When the production costs of a unit are calculated the actual costs are used – not the penalized costs. Default values are assumed to be 1.0.

---

[2] Wood, Wollenberg. “Power Generation, Operation, and Control”, 1996.

1.7.2.2 Availability

Availability assumptions are also defined for each generating resource type and size. These include a Planned Outage Rate ("PLOR") and Forced Outage Rate ("FOR"). These availability assumptions are based on EA&SE estimates and studies using the NERC GADS data.

Fixed maintenance schedules for nuclear plants are input by year with a start date ("STRT_DTE") and an end date ("STP_DTE") based upon current and historical planned refueling outage schedules. These maintenance schedule assumptions are extensions of Nuclear Regulatory Commission published refueling schedules.

Existing generating facilities that are "mothballed" or required to be available for reliability purposes (such as under a "Reliability Must-Run" (RMR) contract) are included as operational units within the MAPS EI database. No adjustments are made to these units to limit their availability or costs (no dispatch penalty factors, no O&M adders, etc.).

1.7.2.3 Operational Constraints

The Minimum Down Time ("MDT") in hours and whether or not the unit is a Must Run resource ("MR") are also specified. If a plant is designated as "Must Run" then (1) the plant is always committed, (2) its minimum capacity is always dispatched, and (3) the remaining capacity is then dispatched according to economic scheduling. These availability assumptions are based on EA&SE studies using the NERC Generating Availability Data System (GADS) data.

Additional operational performance characteristics and assumptions are developed based upon various studies and analyses prepared by EA&SE:

- Minimum Down Time: estimates based upon analysis of actual historical data
- Minimum Up Time: not currently modeled in MAPS
- Must-Run: currently applies to all gas turbine, conventional hydro, and "RMR" or reliability units
- Start-Up Costs: assumptions are based on GE Contract Services estimates of median costs amortizing the inspection and maintenance costs over the number of operating hours or startups that would trigger inspections and maintenance outages
- Planned and Forced Outage Rates: based on EA&SE estimates using the NERC GADS data.

1.7.2.4 Emissions

A "cap and trade" market-based policy tool for regulating emissions is assumed in MAPS. Generators are charged for emissions and must buy allowances for the emissions produced. No emissions offsets or banking of allowances are currently assumed in MAPS. Allowances are reported as a cost, reflecting the actual cost if the allowances are used, or the opportunity cost since the allowances could be sold if not used to support power production.

Non-proprietary assumptions for NO_X, SO_2 and CO_2 emissions are defined for coal, natural gas, oil (#2 and #6) and biomass. Emission rates for individual units are sourced from Ventyx 2009 CEMS report (updated as of February 2010), capturing control

equipment/scrubbers installed until end of year 2009; however, for units that do not report to CEMS default emission rates are applied by fuel. Table 3 lists the default emission rates.

Table 3 - Default Modeled Emission Rates

MAPS Primary Fuel	NO_X Rate (lbs/mmBtu)	SO_2 Rate (lbs/mmBtu)	FROM INSTALL YEAR	Plant Type
COAL	0.050	0.50	1900	ALL
COAL BITUMINOUS	0.050	0.50	1900	ALL
COAL BITUMINOUS	0.050	0.74	2010	ALL
COAL LIGNITE	0.050	0.50	1900	ALL
COAL LIGNITE	0.050	0.80	2010	ALL
COAL SUBBITUMINOUS	0.050	0.50	1900	ALL
COAL SUBBITUMINOUS	0.050	0.27	2010	ALL
COAL WEST BITUMINOUS	0.050	0.50	1900	ALL
COAL WEST BITUMINOUS	0.050	0.32	2010	ALL
FO2OD	0.660	0.33	1900	ALL
FO6OD	0.220	0.44	1900	ALL
GAS	0.040	-	1900	ALL
GAS	0.009	-	1900	CC

1.7.2.5 Program Costs

Additional cost components (such general and administrative costs) are not included in the MAPS EI database. These non production-related cost components may be applied through post-processing calculations or analysis as needed.

1.7.3 Modeling of Gas Turbine Resources

Gas turbine resources are modeled to provide peaking capacity and energy, and are modeled as “Must Run” units. As a Must Run resource, the plant is always committed, its minimum capacity (assumed to be 0) is always dispatched, and the remaining capacity is then dispatched according to economic scheduling. Heat rates of gas turbine plants are sourced from U.S. Gas Turbine World (USGTW) benchtest heat rates. These values have been used to assure that small differences in efficiency (possibly unrealized differences) do not unreasonably bias the analysis. These values are modified to account for aging and inefficiencies associated with warmer or cooler operating temperatures.

1.7.4 Modeling of Combined Cycle Resources

Combined cycle resources are modeled to serve as a load following resource. Heat Rates of combined cycle plants are also sourced from U.S. Gas Turbine World benchtest heat rates. These values have been used to assure that small differences in efficiency (possibly unrealized differences) do not unreasonably bias the analysis. These values are modified to account for aging and inefficiencies associated with warmer or cooler operating temperatures. USGTW values were retained with the exception of Class-E combined cycle plant heat rates, which were reset to experience-based values.

1.7.5 Modeling of Base Load Resources

Coal-fired and nuclear resources are modeled to serve base load requirements. Heat rates assumed in the MAPS database are based upon the average heat rate data provided in the EV dataset.

1.7.6 Modeling of Cogeneration / Private Network Units

Cogeneration or "Private Network" resources in the EI database are modeled based on EV dataset, which is based on US Department of Energy (DOE) EIA-860 database. In general, only the amount of capacity that is available to the grid ("Net to Grid") is modeled in MAPS. The amount of capacity that is designated or contracted to serve the customer's own load ("Host Load," "Behind the Fence" or "Behind the Meter") is not modeled in MAPS, since the load which this capacity serves is also not modeled.

1.7.7 Modeling of Wind Resources

Wind turbine resources are modeled in MAPS using hourly wind generation profiles to more closely reflect the amount and timing of energy available by area. The hourly profiles are based on recent GE studies for the National Renewable Energy Laboratory (NREL), and assigned to the various wind resources in the EI database, based on the source location (longitude and latitude) of each profile.

1.7.8 Modeling of Hydro Resources

Conventional hydro generation resources are modeled in MAPS based on numerical averages of historical monthly generation from 1996 through 2007. Plants are modeled with the following monthly constraints: minimum capacity, maximum capacity, and total volume of available energy. With these assumptions, MAPS seeks to optimize the hydro resource generation and provide regulation and load-following capability.

1.7.9 Modeling of Pumped Storage Hydro Resources

In general, pumped storage resources are assumed to an efficiency of 75% (1.33 MWh of pumping energy required to generate 1 MWh of output). MAPS schedules these resources weekly, and each pumped storage plant is assumed to have 8 hours of storage available.

1.7.10 Ancillary Services Modeling

Ancillary Services (such as operating reserves) are modeled with gas turbines designated as "Must Run" resources and a minimum capacity equal to 0 MW. Using this approach, gas turbines are always committed and available for 10-minute reserve ("Quick Start"). In addition, the current assumption for spinning reserves is 4% of pool load in each hour; if a non-peaking resource is selected to meet spinning reserve requirements, then 20% of maximum capacity for that resource is withheld for meeting the spinning reserve requirements.

1.7.11 Firm Transfers

The EI database reflects approximately 2,900 MW modeled as firm transfers from Hydro Quebec and New Brunswick into NYISO and ISO-NE.

1.8 Expansion Generation Facilities

In the MAPS EI database, generating units with a minimum status of "Under Construction", "Testing", and "Site Prep" have been included. This dataset was reviewed and validated by GE Energy's Global Marketing group, Power Engineering group, and EA&SE using marketing intelligence and internet-based research. Adjustments were made to the EV data (status, expected date of commercial operation, size) as deemed appropriate based on other public data and market intelligence. Default expansion units (generally comprising 60% combined cycle and 40% simple cycle) are included as needed to satisfy reserve margin criteria.

1.9 Demand-Side Resources

Firm demand-side resources, including demand response (DR) and load management (e.g., direct load control, load acting as resource, interruptible loads) are included by modeling as load modifier with zero cost. If it is necessary to model specific demand-side resources as a (peaking) generating resource, the cost of such a resource is assumed to be in excess of the most expensive thermal generating resource (gas turbine). Projections of firm demand-side resources were estimated by EA&SE using information obtained from the NERC 2009 Long-Term Reliability Assessment (Oct. 2009) and are summarized in Table 4 below

Table 4 - Demand Side Resources (MW)

NERC Sub-region	2010	2015	2020
FRCC	3,208	3,465	3,759
MRO	2,566	2,728	2,859
NEP	2,420	2,530	2,530
NYP	2,901	2,901	2,901
RFC	8,200	8,200	8,200
Central (formerly TVA)	1,236	1,225	1,767
Delta (formerly Entergy)	801	801	1,142
Gateway	579	554	781
Southeastern (Southern)	1,416	1,445	2,109
VAC	1,835	1,842	2,683
SPP	834	876	1,382
MRO-Can	448	493	536
Ontario	600	600	600

Non-firm demand resources, including conservation and energy efficiency, are assumed within the energy sales forecasts. No additional load shape modifications or sales forecast reductions were made for non-firm demand resources.

1.10 Transmission & Interchange

As a result of the terrorist events of September 11, 2001 much of the data and information required to model and assess transmission infrastructure in North America, has been deemed Critical Energy Infrastructure Information (CEII). Accordingly, anyone seeking to access detailed transmission data from EA&SE will first need to demonstrate that they are already in possession of the protected data or that they have been approved to receive CEII.

The EI Generation-Transmission data file (GT file) contains assumptions on generating unit location, transmission flow gates and interface limits, line limits, contingencies, and HVDC interconnections and phase shifters. Many of the transmission constraint limit values modeled in MAPS were obtained through Non-Disclosure Agreements (NDA) with RTO/ISOs or transmission providers. Accordingly, anyone seeking to access those limit values will need to sign the same NDA and provide copies to EA&SE before those values can be disclosed. Each generating unit modeled in the EI Database is assigned to the respective generator bus on the EI system, based on the EI load flow data dictionary (CEII) and EV data. Flow gates and interface definitions for the EI are based on the July 9, 2009 NERC Book of Flowgates, the most recent operational constraints or "nomograms" posted on ISO/RTO websites in 2009, and the most recent regional transmission assessments published by RTOs, ISOs and/or local transmission providers. Line limit assumptions are based on ratings provided within the load flow case that has been selected for the database update (described below). HVDC and phase shifters are based on the load flow case that has been selected for the database update. Contingencies are updated on an ongoing basis and are based on the same interface limit assumption documents - namely:

- The July 9, 2009 NERC Book of Flowgates;
- The most recent nomograms posted on ISO/RTO websites in 2009, and
- Regional transmission assessments published by transmission providers in 2009.

1.10.1 Load Flow Models

The transmission model in MAPS is obtained from a solved AC load flow. The transmission model in the EI Database is based on the 2009 Summer Peak load flow case (2008 Series) released by the Multi-Regional Model Working Group (MMWG), which formerly fell under the purview of NERC but currently falls under the purview of the Eastern Interconnection Reliability Assessment Group (ERAG). Additionally, select recently announced transmission projects for NYISO, ISONE and PJM have been added to the load flows.

1.10.2 Transmission Constraints

The EI database reflects all transmission interfaces defined within the NERC Book of Flowgates (BOF) as well as selected "New England Potentially Limiting Bulk Transmission Interfaces" as defined in the 2008 New England Power Pool (NEPOOL) FERC Form 715 filings. The EI database models the flow limits of transmission lines, interfaces, contingencies, Phase Angle Regulators (PARs) and High Voltage DC (HVDC) lines. The flow limits of lines, interfaces and contingencies were obtained from the 2007 Summer NERC Book of Flowgates released on October 9, 2007 and from the 2008 NEPOOL FERC Form 715 filings for the New England region.

In addition to the interface limits, the flows across all Phase Angle Regulators (PARs) and High Voltage DC (HVDC) transmission lines in the EI are monitored subject to their capabilities.

The EI Database also contains hurdle rates that represent the wheeling and other transactional costs between the various RTOs/NERC regions in the EI.

Additional information on transmission system data sources is provided in Appendix E.

Appendix A: Availability Assumptions

Standard assumptions for modeling Planned Outage Rates (PLOR) and Forced Outage Rates (FOR) are listed below.

Table A-1 – Outage Rate Assumptions

TECHTYPE	FUEL	PLOR	FOR
STST	COAL	0.072	0.05
STST	GAS	0.0669	0.02
STST	OTHER	0.0669	0.02
STST	OIL	0.0544	0.03
CC	ALL	0.048	0.03
IGCC	ALL	0.04	0.03
SCGT	ALL	0.0151	0.03
IC	ALL	0.0151	0.03
OTHER-RENEW	0	0.0151	0.03
SOLAR-RENEW	0	0.0151	0.03

Appendix B: NERC Sub-regions Within the EI

This appendix shows the mappings of the various NERC sub-regions and control areas contained within the MAPS EI database. (Images sourced from Ventyx Energy Velocity.)

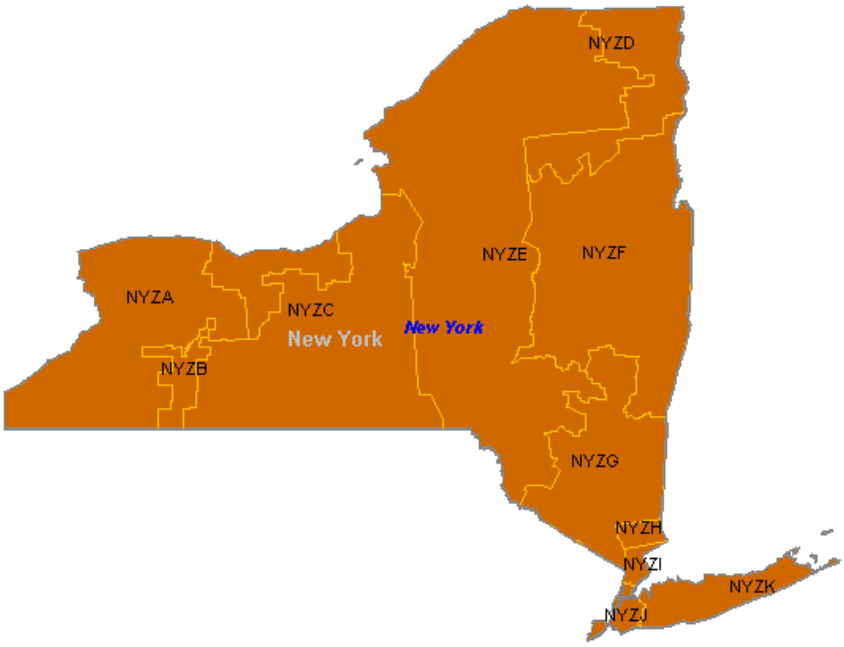


Figure B - 1 - New York

Figure B - 2 - New England

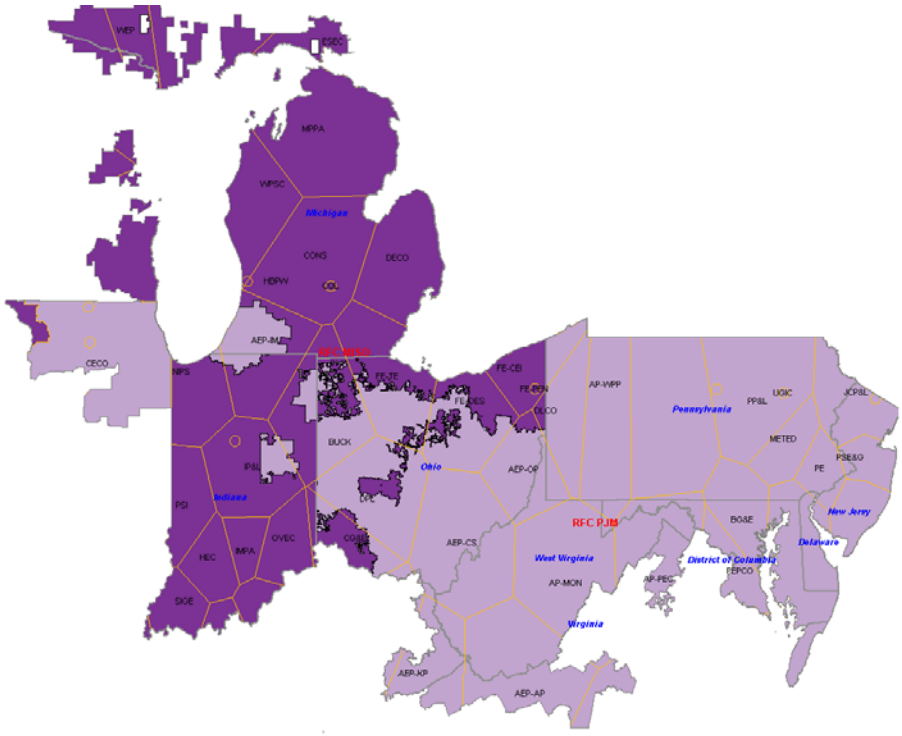


Figure B - 3 - Reliability First Corporation (RFC)

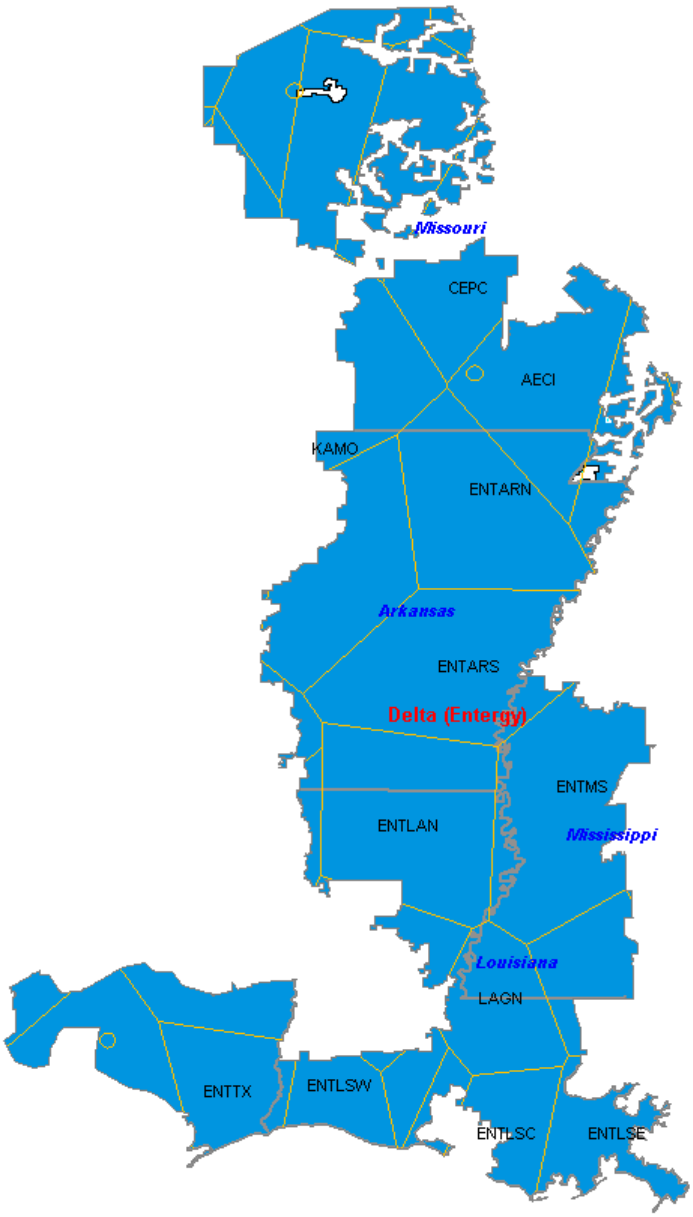


Figure B - 4 – Delta (Entergy)

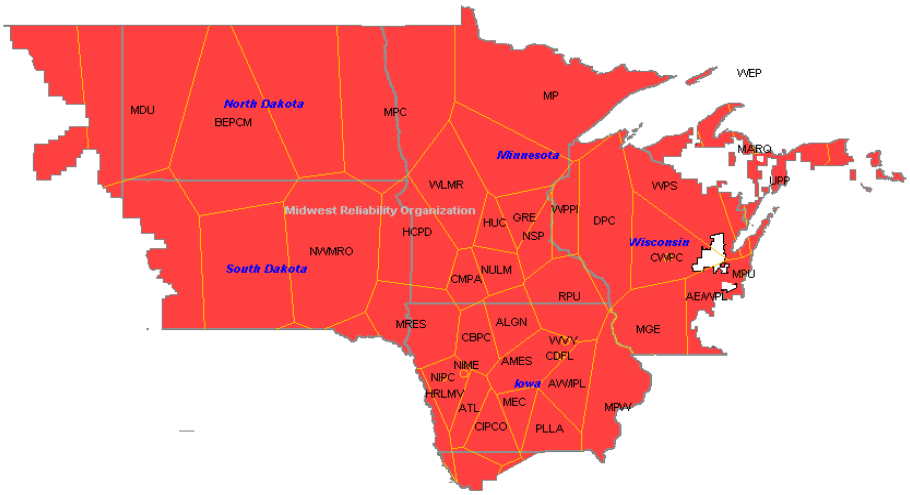


Figure B - 5 – Midwest Reliability Organization (MRO)

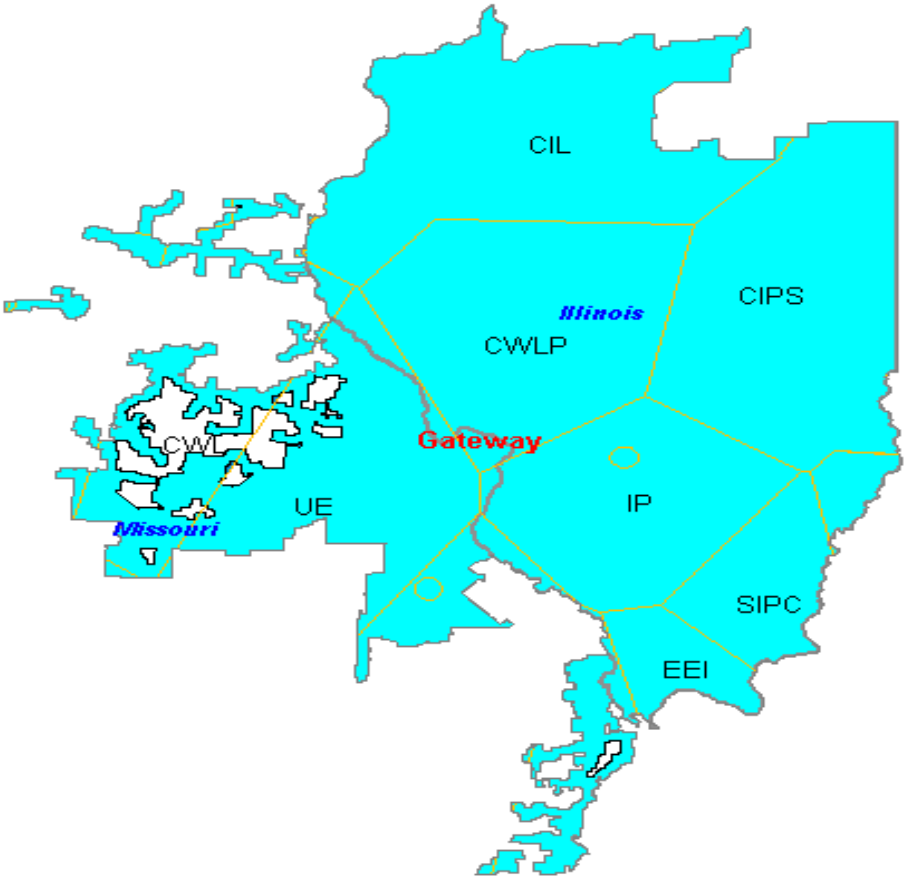


Figure B - 6 – Gateway

Figure B - 7 – Ontario

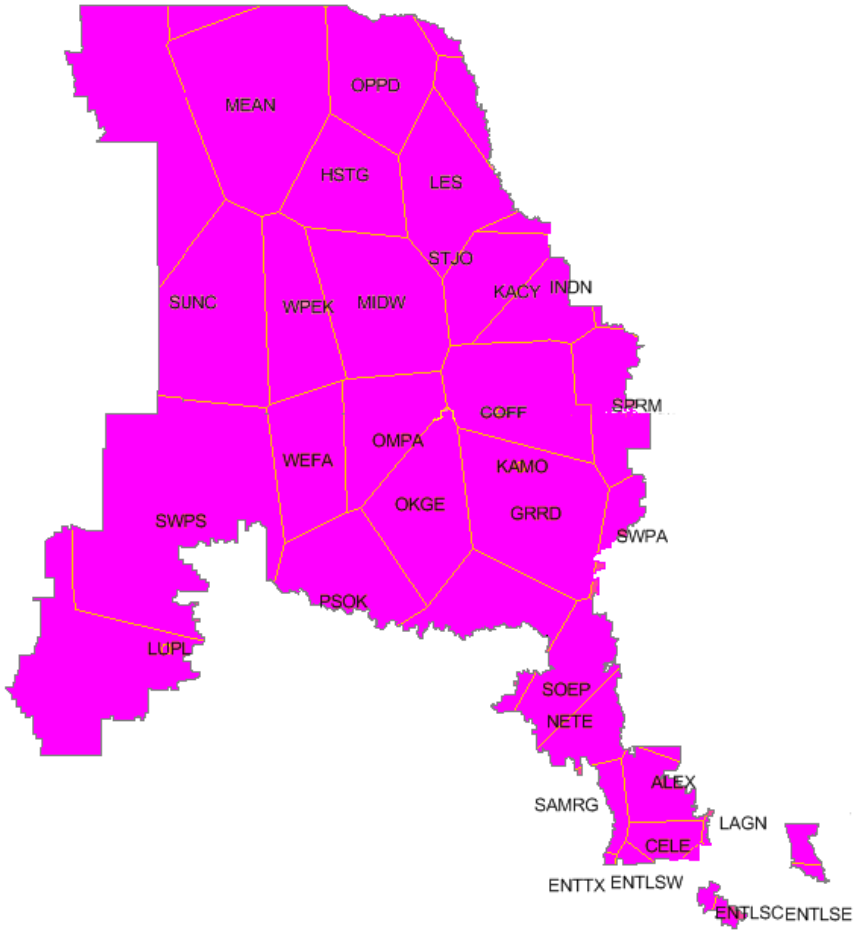


Figure B - 8 – Southwest Power Pool (SPP)

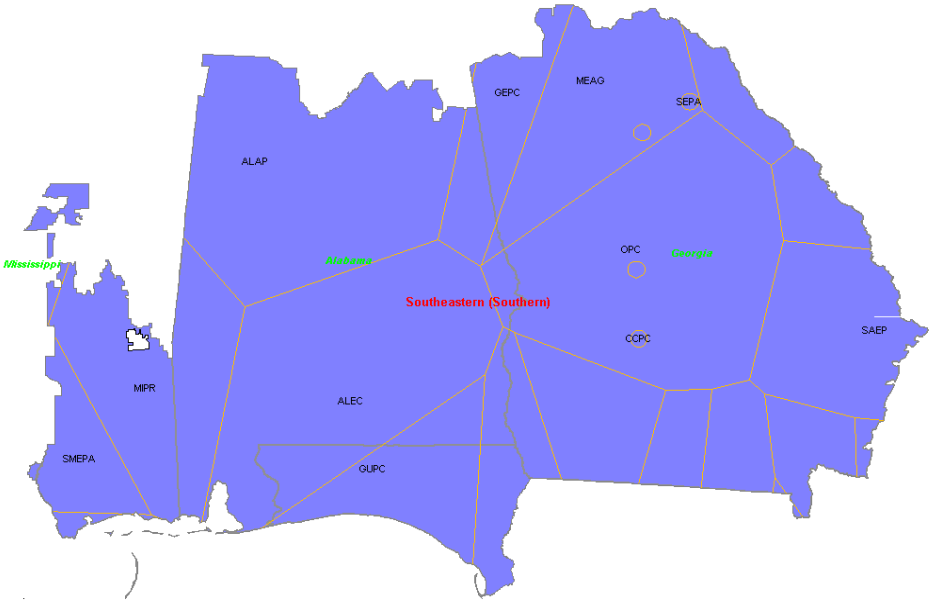


Figure B - 9 – Southeastern

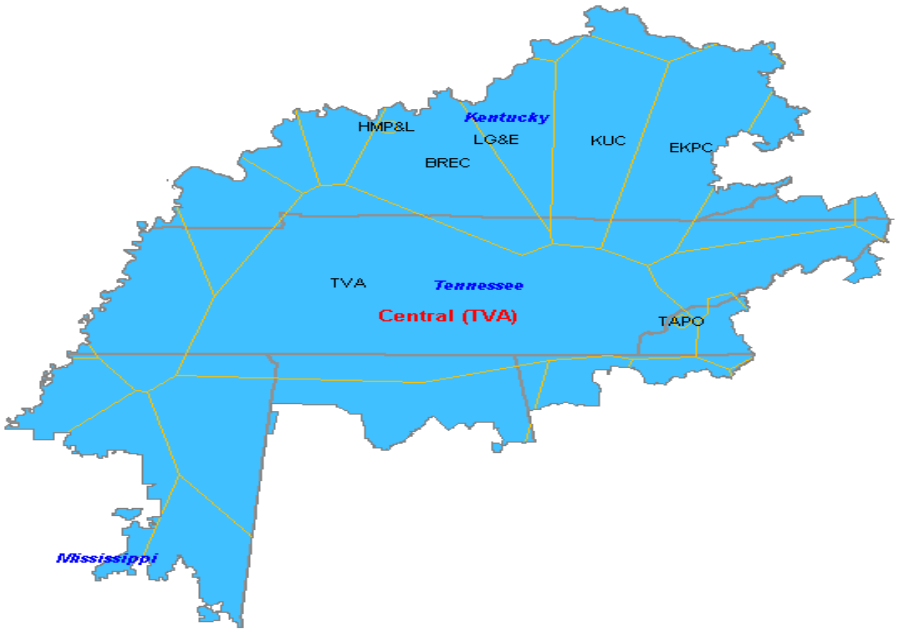


Figure B - 10 – Central (TVA)

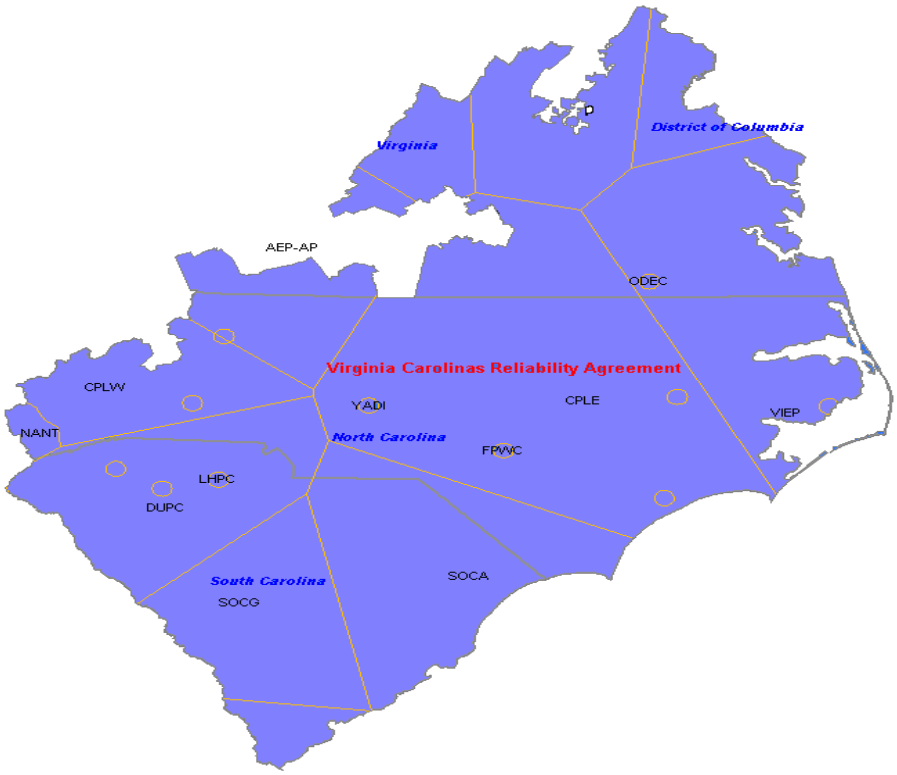


Figure B - 11 – Virginia Carolinas Reliability Agreement (VACAR)

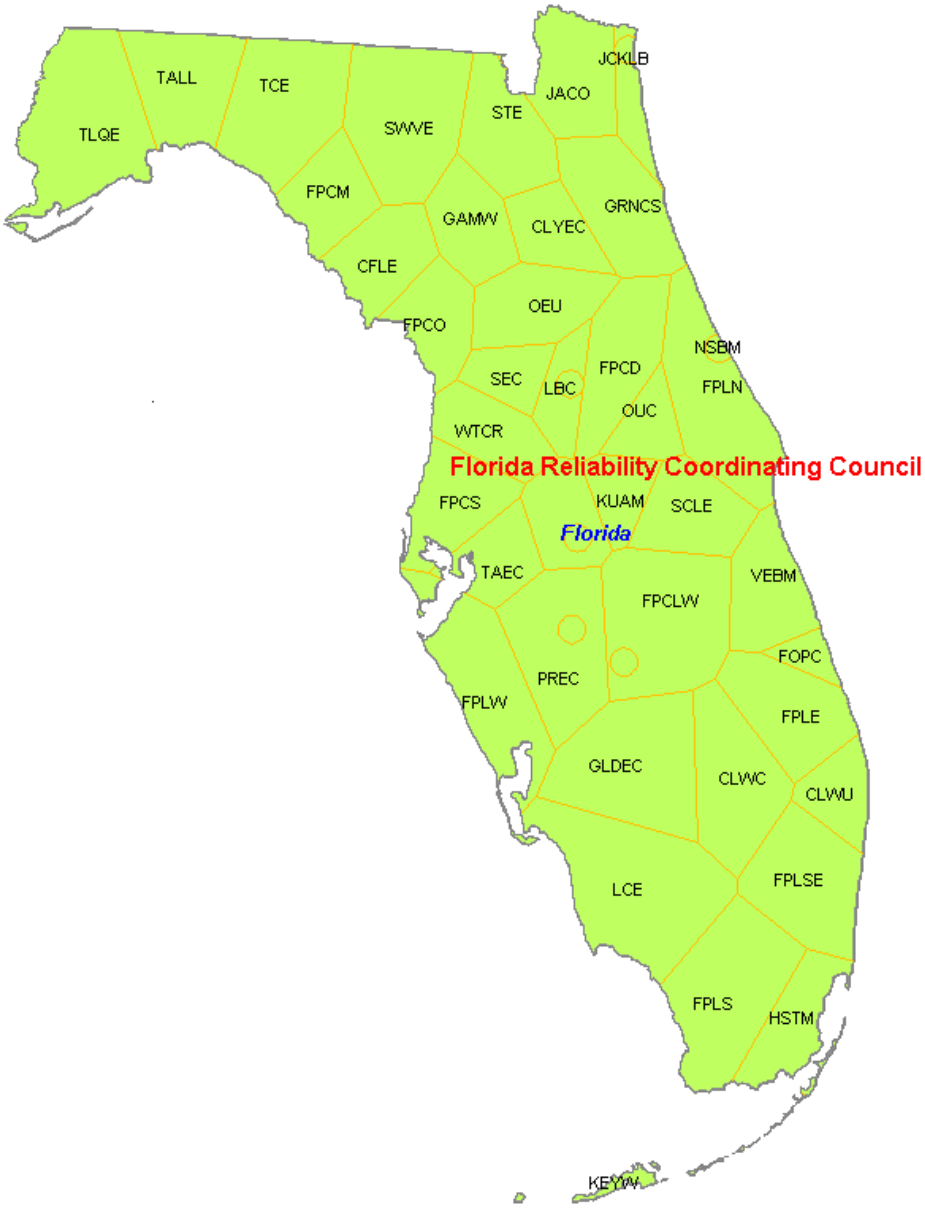


Figure B - 12 – Florida Reliability Coordinating Agreement (FRCC)

Appendix C: Key to Unit Types and Fuel Names

This appendix provides in tabular format the unit type abbreviations, primary fuel names, and a brief clarifying note as to the applicable technology used in the EI database.

Table C-1 – Unit Types, Fuel Names and Associated Technologies

Unit Type	Primary Fuel Name	Technology
CCCC	FO2OD	COMBINED CYCLE - Oil
CCCC	FO6OD	COMBINED CYCLE - Oil
CCCC	NGAL	COMBINED CYCLE - Gas
CCCC	NGAR	COMBINED CYCLE - Gas
CCCC	NGCT	COMBINED CYCLE - Gas
CCCC	NGDE	COMBINED CYCLE - Gas
CCCC	NGFLCENE	COMBINED CYCLE - Gas
CCCC	NGFLCENW	COMBINED CYCLE - Gas
CCCC	NGFLNORT	COMBINED CYCLE - Gas
CCCC	NGFLPANH	COMBINED CYCLE - Gas
CCCC	NGFLSOUT	COMBINED CYCLE - Gas
CCCC	NGGA	COMBINED CYCLE - Gas
CCCC	NGIA	COMBINED CYCLE - Gas
CCCC	NGILOTHE	COMBINED CYCLE - Gas
CCCC	NGINOTHE	COMBINED CYCLE - Gas
CCCC	NGKS	COMBINED CYCLE - Gas
CCCC	NGLANORT	COMBINED CYCLE - Gas
CCCC	NGLASOUT	COMBINED CYCLE - Gas
CCCC	NGMABOST	COMBINED CYCLE - Gas
CCCC	NGMAOTHE	COMBINED CYCLE - Gas
CCCC	NGMD	COMBINED CYCLE - Gas
CCCC	NGME	COMBINED CYCLE - Gas
CCCC	NGMIDETR	COMBINED CYCLE - Gas
CCCC	NGMIOTHE	COMBINED CYCLE - Gas
CCCC	NGMN	COMBINED CYCLE - Gas
CCCC	NGMO	COMBINED CYCLE - Gas
CCCC	NGMS	COMBINED CYCLE - Gas
CCCC	NGNC	COMBINED CYCLE - Gas
CCCC	NGNE	COMBINED CYCLE - Gas
CCCC	NGNH	COMBINED CYCLE - Gas
CCCC	NGNJ	COMBINED CYCLE - Gas
CCCC	NGNYEAST	COMBINED CYCLE - Gas
CCCC	NGNYNYCL	COMBINED CYCLE - Gas
CCCC	NGNYWEST	COMBINED CYCLE - Gas
CCCC	NGOHOTHE	COMBINED CYCLE - Gas
CCCC	NGOK	COMBINED CYCLE - Gas
CCCC	NGON	COMBINED CYCLE - Gas
CCCC	NGPAEAST	COMBINED CYCLE - Gas
CCCC	NGPAWEST	COMBINED CYCLE - Gas
CCCC	NGRI	COMBINED CYCLE - Gas
CCCC	NGSC	COMBINED CYCLE - Gas
CCCC	NGTN	COMBINED CYCLE - Gas
CCCC	NGVA	COMBINED CYCLE - Gas

Table C-1 – Unit Types, Fuel Names and Associated Technologies

Unit Type	Primary Fuel Name	Technology
CCCC	NGWI	COMBINED CYCLE - Gas
CCCC	WASTE	COMBINED CYCLE - Waste
DDGT	DDENT	DISPATCHABLE DEMAND
DDGT	DDFRC	DISPATCHABLE DEMAND
DDGT	DDMISO	DISPATCHABLE DEMAND
DDGT	DDNEB	DISPATCHABLE DEMAND
DDGT	DDNEP	DISPATCHABLE DEMAND
DDGT	DDNYP	DISPATCHABLE DEMAND
DDGT	DDONT	DISPATCHABLE DEMAND
DDGT	DDPJM	DISPATCHABLE DEMAND
DDGT	DDSOU	DISPATCHABLE DEMAND
DDGT	DDSPP	DISPATCHABLE DEMAND
DDGT	DDTVA	DISPATCHABLE DEMAND
DDGT	DDVAC	DISPATCHABLE DEMAND
EXCC	NGFLSOUT	COMBINED CYCLE - Gas
EXCC	NGILOTHE	COMBINED CYCLE - Gas
EXCC	NGMIOTHE	COMBINED CYCLE - Gas
EXCC	NGMN	COMBINED CYCLE - Gas
EXCC	NGNYNYCL	COMBINED CYCLE - Gas
EXCC	NGNYWEST	COMBINED CYCLE - Gas
EXCC	NGOHOTHE	COMBINED CYCLE - Gas
EXGT	NGFLSOUT	GAS TURBINE - Gas
EXGT	NGILOTHE	GAS TURBINE - Gas
EXGT	NGMIOTHE	GAS TURBINE - Gas
EXGT	NGMN	GAS TURBINE - Gas
EXGT	NGNJ	GAS TURBINE - Gas
EXGT	NGNYNYCL	GAS TURBINE - Gas
EXGT	NGNYWEST	GAS TURBINE - Gas
EXGT	NGOHOTHE	GAS TURBINE - Gas
EXGT	NGPAEAST	GAS TURBINE - Gas
EXSP		Expansion Solar PV
EXWH		Expansion Wind modeled as hourly modifier
GTGT	FO2OD	GAS TURBINE - Oil
GTGT	FO6OD	GAS TURBINE - Oil
GTGT	NGAL	GAS TURBINE - Gas
GTGT	NGAR	GAS TURBINE - Gas
GTGT	NGCT	GAS TURBINE - Gas
GTGT	NGDE	GAS TURBINE - Gas
GTGT	NGFLCENE	GAS TURBINE - Gas
GTGT	NGFLCENW	GAS TURBINE - Gas
GTGT	NGFLNORT	GAS TURBINE - Gas
GTGT	NGFLPANH	GAS TURBINE - Gas
GTGT	NGFLSOUT	GAS TURBINE - Gas
GTGT	NGGA	GAS TURBINE - Gas
GTGT	NGIA	GAS TURBINE - Gas
GTGT	NGILCHIC	GAS TURBINE - Gas
GTGT	NGILOTHE	GAS TURBINE - Gas

Table C-1 – Unit Types, Fuel Names and Associated Technologies

Unit Type	Primary Fuel Name	Technology
GTGT	NGINGARY	GAS TURBINE - Gas
GTGT	NGINOTHE	GAS TURBINE - Gas
GTGT	NGKS	GAS TURBINE - Gas
GTGT	NGKY	GAS TURBINE - Gas
GTGT	NGLANORT	GAS TURBINE - Gas
GTGT	NGLASOUT	GAS TURBINE - Gas
GTGT	NGMABOST	GAS TURBINE - Gas
GTGT	NGMAOTHE	GAS TURBINE - Gas
GTGT	NGMD	GAS TURBINE - Gas
GTGT	NGME	GAS TURBINE - Gas
GTGT	NGMIDETR	GAS TURBINE - Gas
GTGT	NGMIOTHE	GAS TURBINE - Gas
GTGT	NGMN	GAS TURBINE - Gas
GTGT	NGMO	GAS TURBINE - Gas
GTGT	NGMS	GAS TURBINE - Gas
GTGT	NGNC	GAS TURBINE - Gas
GTGT	NGND	GAS TURBINE - Gas
GTGT	NGNE	GAS TURBINE - Gas
GTGT	NGNH	GAS TURBINE - Gas
GTGT	NGNJ	GAS TURBINE - Gas
GTGT	NGNYEAST	GAS TURBINE - Gas
GTGT	NGNYNYCL	GAS TURBINE - Gas
GTGT	NGNYWEST	GAS TURBINE - Gas
GTGT	NGOHCLEV	GAS TURBINE - Gas
GTGT	NGOHOTHE	GAS TURBINE - Gas
GTGT	NGOK	GAS TURBINE - Gas
GTGT	NGON	GAS TURBINE - Gas
GTGT	NGPAEAST	GAS TURBINE - Gas
GTGT	NGPAWEST	GAS TURBINE - Gas
GTGT	NGSC	GAS TURBINE - Gas
GTGT	NGSD	GAS TURBINE - Gas
GTGT	NGTN	GAS TURBINE - Gas
GTGT	NGVA	GAS TURBINE - Gas
GTGT	NGVT	GAS TURBINE - Gas
GTGT	NGWI	GAS TURBINE - Gas
GTGT	NGWV	GAS TURBINE - Gas
GTGT	OTHER	GAS TURBINE - Other
GTGT	WASTE	GAS TURBINE - Waste
HYHY		Hydro
ICIC	BIOMASS	INTERNAL COMBUSTION - Biomass
ICIC	FO2OD	INTERNAL COMBUSTION - Oil
ICIC	FO6OD	INTERNAL COMBUSTION - Oil
ICIC	NGAR	INTERNAL COMBUSTION - Gas
ICIC	NGFLCENE	INTERNAL COMBUSTION - Gas
ICIC	NGFLSOUT	INTERNAL COMBUSTION - Gas
ICIC	NGIA	INTERNAL COMBUSTION - Gas
ICIC	NGILOTHE	INTERNAL COMBUSTION - Gas

Table C-1 – Unit Types, Fuel Names and Associated Technologies

Unit Type	Primary Fuel Name	Technology
ICIC	NGKS	INTERNAL COMBUSTION - Gas
ICIC	NGLANORT	INTERNAL COMBUSTION - Gas
ICIC	NGMIOTHE	INTERNAL COMBUSTION - Gas
ICIC	NGMN	INTERNAL COMBUSTION - Gas
ICIC	NGMO	INTERNAL COMBUSTION - Gas
ICIC	NGNE	INTERNAL COMBUSTION - Gas
ICIC	NGNJ	INTERNAL COMBUSTION - Gas
ICIC	NGNYNYCL	INTERNAL COMBUSTION - Gas
ICIC	NGOK	INTERNAL COMBUSTION - Gas
ICIC	NGPAWEST	INTERNAL COMBUSTION - Gas
ICIC	NGSD	INTERNAL COMBUSTION - Gas
ICIC	NGWI	INTERNAL COMBUSTION - Gas
ICIC	WASTE	INTERNAL COMBUSTION - Waste
IGCC	FRC-COAL	INTEGRATED GASIFICATION COMBINED CYCLE - Coal
IGCC	MIS-COAL	INTEGRATED GASIFICATION COMBINED CYCLE - Coal
IGCC	NGDE	INTEGRATED GASIFICATION COMBINED CYCLE - Gas
IGCC	PJM-COAL	INTEGRATED GASIFICATION COMBINED CYCLE - Coal
IGCC	TVA-COAL	INTEGRATED GASIFICATION COMBINED CYCLE - Coal
IMIM	NGMN	Imports
IMIM	NGNYWEST	Imports
IMIM	NGON	Imports
IMIM		Imports
NUNU	NUCLEAR	Nuclear
PSH		Pumped Storage Hydro
STST	BIOMASS	STEAM TURBINE - Biomass
STST	ENT-COAL	STEAM TURBINE - Coal
STST	FO2OD	STEAM TURBINE - Oil
STST	FO6OD	STEAM TURBINE - Oil
STST	FRC-COAL	STEAM TURBINE - Coal
STST	MIS-COAL	STEAM TURBINE - Coal
STST	NEB-COAL	STEAM TURBINE - Coal
STST	NEP-COAL	STEAM TURBINE - Coal
STST	NGAL	STEAM TURBINE - Gas
STST	NGAR	STEAM TURBINE - Gas
STST	NGCT	STEAM TURBINE - Gas
STST	NGDE	STEAM TURBINE - Gas
STST	NGFLCENE	STEAM TURBINE - Gas
STST	NGFLCENW	STEAM TURBINE - Gas
STST	NGFLNORT	STEAM TURBINE - Gas
STST	NGFLPANH	STEAM TURBINE - Gas
STST	NGFLSOUT	STEAM TURBINE - Gas
STST	NGGA	STEAM TURBINE - Gas
STST	NGIA	STEAM TURBINE - Gas
STST	NGILOTHE	STEAM TURBINE - Gas
STST	NGINGARY	STEAM TURBINE - Gas
STST	NGINOTHE	STEAM TURBINE - Gas
STST	NGKS	STEAM TURBINE - Gas

Table C-1 – Unit Types, Fuel Names and Associated Technologies

Unit Type	Primary Fuel Name	Technology
STST	NGLANORT	STEAM TURBINE - Gas
STST	NGLASOUT	STEAM TURBINE - Gas
STST	NGMABOST	STEAM TURBINE - Gas
STST	NGMAOTHE	STEAM TURBINE - Gas
STST	NGMD	STEAM TURBINE - Gas
STST	NGME	STEAM TURBINE - Gas
STST	NGMIDETR	STEAM TURBINE - Gas
STST	NGMIOTHE	STEAM TURBINE - Gas
STST	NGMN	STEAM TURBINE - Gas
STST	NGMO	STEAM TURBINE - Gas
STST	NGMS	STEAM TURBINE - Gas
STST	NGNE	STEAM TURBINE - Gas
STST	NGNJ	STEAM TURBINE - Gas
STST	NGNYEAST	STEAM TURBINE - Gas
STST	NGNYNYCL	STEAM TURBINE - Gas
STST	NGNYWEST	STEAM TURBINE - Gas
STST	NGOHCLEV	STEAM TURBINE - Gas
STST	NGOHOTHE	STEAM TURBINE - Gas
STST	NGOK	STEAM TURBINE - Gas
STST	NGON	STEAM TURBINE - Gas
STST	NGPAEAST	STEAM TURBINE - Gas
STST	NGPAWEST	STEAM TURBINE - Gas
STST	NGVA	STEAM TURBINE - Gas
STST	NGWI	STEAM TURBINE - Gas
STST	NGWV	STEAM TURBINE - Gas
STST	NYP-COAL	STEAM TURBINE - Coal
STST	ONT-COAL	STEAM TURBINE - Coal
STST	OTHER	STEAM TURBINE - Other
STST	PJM-COAL	STEAM TURBINE - Coal
STST	SOU-COAL	STEAM TURBINE - Coal
STST	SPP-COAL	STEAM TURBINE - Coal
STST	TVA-COAL	STEAM TURBINE - Coal
STST	VAC-COAL	STEAM TURBINE - Coal
STST	WASTE	STEAM TURBINE - Waste
STST	WOOD	STEAM TURBINE - Wood
WHFC		Wind Forecast Unit
WHRM		Wind Unit

Appendix D: Load Forecast Development

This appendix provides a more detailed discussion on the development of the EA&SE load forecast.

In order to determine the supply and demand balance for North America and develop dispatch analyses using MAPS, a reasonable forecast of electricity demand, annual peak demand, hourly load shapes and total energy demand, must be established. The starting point for the calculations for the 2010 energy and peak demand forecast update is the 2009 North American Electric Reliability Council (NERC) Electricity Supply and Demand (ES&D) database report issued in December 2009. The NERC ES&D includes both annual peak demands and net energies for load by NERC region and sub-region.

In previous years, the NERC data were used for analysis as published. However, since the NERC forecast data had a time lag, it did not capture recent economic effects well. Therefore, a process was developed to adjust the forecast to reflect this recent economic downturn and current anticipated level of rebound.

Actual load data are provided through 2008 from NERC ES&D.

The forecast energy for the US is developed based on the correlation of historical electricity energy growth to GDP. The GDP forecast is from Global Insight's February 2010 monthly update[3]. The correlation of GDP to electricity intensity (kWh/$GDP) is calculated (Figure D-1 and Table D-1) then the growth rate is applied to estimate the escalation for "Net Energy for Load" values. Each NERC sub-region's growth is calculated as the sub-region's percent share of the total system growth from 2009 NERC ES&D data. This approach is used for 2010-2020 (Table D-2). To address de-escalation in 2009, regional de-escalation rates are applied and taken from EEI Weekly Output Report 52 Weeks Ended Data for Jan 2010. Beginning in 2021, the average regional growth factors from 2016-2020 are used.

[3] Global Insight file: "wor_a_c.xls"

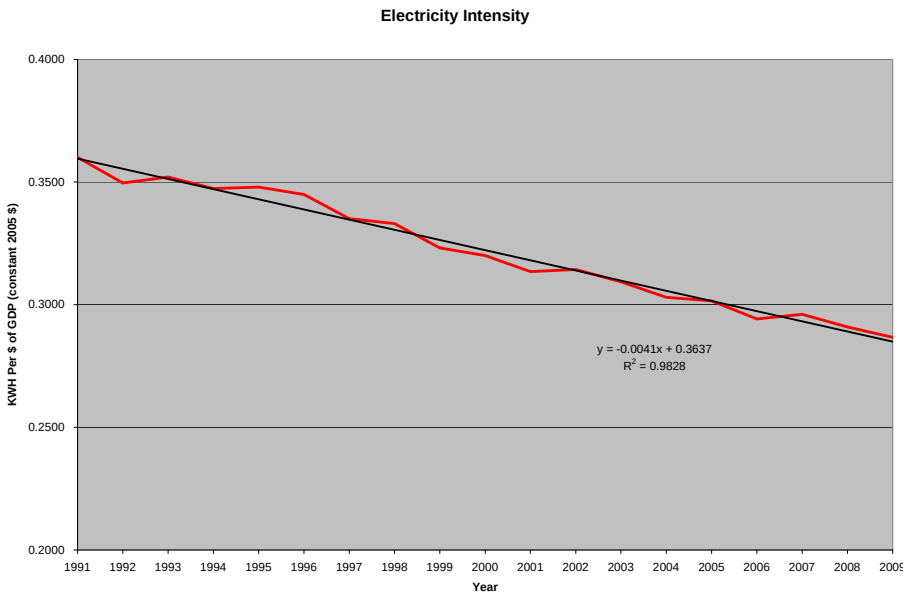


Figure D - 1 Historical Electricity Intensity Trend

Table D-1 –Electricity Growth Outlook (sources: Global Insight, NERC)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Electricity growth	-3.8%	1.5%	1.4%	.2%	1.6%	1.1%	0.8%	0.8%	0.8%	1.0%	1.2%	1.2%

Table D-2 – System Growth (Energy) (source: NERC)

Region	Subregion	Country	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
ECAR	-	US										
ERCOT	-	US	-1.3%	1.1%	1.5%	3.4%	2.8%	1.5%	1.3%	1.1%	1.1%	1.2%
FRCC	-	US	-3.2%	0.5%	1.3%	2.7%	1.8%	1.2%	1.2%	1.0%	1.3%	1.6%
MAAC	-	US										
MAIN	-	US										
MRO	-	US	-5.7%	3.3%	1.4%	1.6%	1.4%	0.9%	0.9%	0.7%	0.8%	1.0%
NPCC	-	US										
	New England	US	-3.8%	0.0%	0.5%	1.4%	0.5%	0.8%	0.7%	0.6%	0.7%	0.8%
	New York	US	-3.8%	-0.1%	0.3%	0.6%	0.3%	0.5%	0.4%	0.5%	0.5%	0.6%
RFC	-	US										
	MISO		-5.7%	1.3%	0.7%	1.2%	1.1%	0.8%	0.7%	0.6%	0.6%	0.8%
	PJM		-3.4%	1.1%	1.9%	3.7%	1.6%	1.1%	0.8%	0.8%	0.5%	0.7%
SERC	-	US										
	Central	US	-3.2%	0.1%	0.8%	1.5%	1.6%	0.6%	-0.6%	0.1%	0.8%	1.0%
	Delta	US	-3.2%	0.8%	2.6%	1.7%	1.9%	2.1%	0.8%	0.7%	0.7%	0.8%
	Gateway	US	-3.2%	3.9%	1.0%	1.1%	0.6%	0.4%	0.6%	0.5%	0.5%	0.6%
	Southeastern	US	-3.2%	3.5%	1.9%	2.6%	2.4%	1.5%	1.2%	1.0%	1.2%	1.0%
	VACAR	US	-3.2%	2.0%	1.5%	2.4%	1.7%	1.2%	1.0%	1.0%	1.0%	1.2%
SPP	-	US	-5.3%	2.1%	1.5%	2.0%	1.5%	1.1%	-0.1%	0.9%	0.9%	1.1%
WECC	-	US										
	AZ-NM-SNV	US	-2.4%	2.9%	1.6%	2.9%	2.5%	1.9%	1.7%	1.3%	1.5%	1.7%
	CA-MX US	US	-2.4%	1.5%	0.9%	1.5%	1.3%	0.9%	0.8%	0.6%	0.7%	0.8%
	NWPP	US	-2.6%	2.0%	1.0%	1.8%	1.5%	1.0%	0.9%	0.8%	0.7%	1.0%
	RMPA	US	-2.8%	1.2%	1.9%	-1.0%	2.2%	1.4%	1.2%	1.2%	1.2%	1.5%
TOTAL	**-**	**US**	-3.5%	1.5%	1.4%	2.2%	1.6%	1.1%	0.8%	0.8%	0.8%	1.0%

For 2009, the US peak demand is estimated based on the last four years' actual average load factor (2005-2008) (Table D-3). From 2010 to 2020 the GDP-to-energy intensity correlation is used as with the energy forecast (Table D-4). Actual peak demand data for 2009 were available for a few sub-regions including: ERCOT – 63,400 MW actual compared to 62,167 MW estimate; ISONE – 25,081 MW actual compared to 25,406MW estimate; and NYISO – 30,844 MW actual compared to 31,638 MW estimate. Beginning in 2021, the average regional growth factors from 2016-2020 are used.

Table D-3 – System Load Factor by NERC Sub-Region (source: NERC)

Region	Subregion	Country	2005	2006	2007	2008	2009
ECAR	-	US					
ERCOT	-	US	56.7%	56.0%	56.4%	57.4%	56.6%
FRCC	-	US	55.7%	57.4%	56.8%	57.8%	56.9%
MAAC	-	US					
MAIN	-	US					
MRO	-	US	62.0%	60.3%	59.6%	65.5%	61.8%
NPCC	-	US	58.8%	53.1%	59.1%	58.0%	57.2%
	New England	US	57.9%	53.6%	58.7%	57.6%	56.9%
	New York	US	59.5%	52.7%	59.4%	58.3%	57.5%
RFC	-	US	60.3%	55.1%	60.0%	63.2%	59.6%
	MISO				61.9%	63.7%	62.8%
	PJM				59.9%	63.4%	61.7%
SERC	-	US	57.6%	58.0%	57.3%	59.2%	58.0%
	Central	US	62.8%	61.5%	61.8%	65.4%	62.9%
	Delta	US	58.8%	59.3%	57.3%	58.5%	58.5%
	Gateway	US	49.0%	55.9%	56.3%	57.1%	54.6%
	Southeasterr	US	58.5%	58.2%	55.8%	57.0%	57.4%
	VACAR	US	56.0%	55.6%	55.6%	57.6%	56.2%
SPP	-	US	55.1%	53.6%	55.8%	54.5%	54.8%
WECC	-	US	59.9%	57.8%	60.5%	63.1%	60.3%
	AZ-NM-SNV	US	51.6%	51.2%	51.9%	54.3%	52.2%
	CA-MX US	US	54.6%	52.3%	55.0%	57.4%	54.8%
	NWPP	US	73.9%	70.2%	71.9%	73.7%	72.4%
	RMPA	US	60.9%	64.0%	59.9%	64.2%	62.3%
TOTAL	**-**	**US**	58.7%	56.6%	58.6%	60.5%	58.6%

Table D-4 – Peak Demand Outlook (MW) (source: NERC)

Region	Subregion	Country	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ECAR	-	US	0										
ERCOT	-	US	62167	62,789	63,631	65,688	67,578	68,574	69,339	69,975	70,777	71,625	72,643
FRCC	-	US	44029	44,095	44,456	45,553	46,383	47,016	47,625	48,191	48,771	49,615	50,629
MAAC	-	US											
MAIN	-	US											
MRO	-	US	39623	40,735	41,236	41,959	42,554	42,949	43,294	43,629	43,934	44,354	44,858
NPCC	-	US											
	New England	US	25406	25,719	25,962	26,444	26,769	27,036	27,245	27,404	27,554	27,732	27,946
	New York	US	31638	31,625	31,773	32,004	32,168	32,326	32,426	32,599	32,756	32,989	33,269
RFC	-	US											
	MISO		54274	54,739	55,779	56,050	56,103	56,304	56,480	56,684	56,902	57,128	57,399
	PJM		110748	112,226	114,262	118,303	120,541	121,707	122,595	123,347	124,115	125,026	126,121
SERC	-	US											
	Central	US	42145	42,331	42,754	43,481	44,469	45,059	45,294	45,660	45,970	46,454	47,035
	Delta	US	27049	27,411	28,023	28,515	28,980	29,407	29,609	29,797	29,982	30,216	30,496
	Gateway	US	19329	19,824	20,038	20,206	20,308	20,375	20,474	20,560	20,657	20,774	20,914
	Southeasterr	US	46942	48,499	49,476	50,846	51,945	52,754	53,397	53,984	54,644	55,283	56,052
	VACAR	US	61603	62,832	63,715	65,413	66,595	67,400	68,073	68,702	69,362	70,218	71,247
SPP	-	US	40980	41,696	42,209	42,889	43,491	43,883	43,810	44,164	44,520	44,969	45,508
WECC	-	US											
	AZ-NM-SNV	US	29270	29,813	30,140	30,958	31,559	32,181	32,710	33,119	33,635	34,203	34,886
	CA-MX US	US	59517	60,341	60,819	61,738	62,532	63,103	63,603	64,039	64,477	65,049	65,737
	NWPP	US	38448	39,363	39,819	40,773	41,430	41,945	42,363	42,754	43,132	43,652	44,276
	RMPA	US	11603	11,612	11,781	12,042	12,281	12,449	12,586	12,719	12,838	13,028	13,256
TOTAL	**-**	**US**	**744771**	**755650**	**765872**	**782861**	**795686**	**804467**	**810924**	**817327**	**824027**	**832315**	**842270**

For Canada and Baja-Mexico, the same approaches are used for year 2009 as with the US. However, starting in 2010, 2009 NERC ES&D escalation rates are applied since many sub-regions experience de-escalation that cannot be calculated properly with the same methods that are applied to the US load (where each year past 2010 is escalating, not de-escalating).

The result is a large drop in peak demand from the 2009 NERC ES&D (sheets included for reference) and EA&SE Aug 2009 demand forecast of ~67 GW by 2018. US energy demand growth rates average 1.2% from 2010 to 2020 and 1.0% from 2021 to 2030. Energy demand growth rates in 2021 and beyond are held at the 2021 levels.

Demand-side management (DSM), interruptible loads and energy efficiency are not explicitly included in these values. The DSM and interruptible load estimates are taken

directly form the 2009 NERC ES&D Long-Term Reliability Assessment and are modeled separately in MAPS and reserve margin calculations. Energy efficiency is calculated based on RPS/RES assumptions and also modeled separately so that adjustments easily may be made as policy assumptions change over time.

Appendix E: Transmission System

This appendix outlines transmission system data sources, data management, documentation, and data protection guidelines/requirements (including CEII-related matters).

Sources of Transmission Constraint Data

Over 1,600 transmission constraints are represented within the MAPS Eastern Interconnection model. There are a variety of different sources for the definitions and ratings of those constraints, these include:

- The NERC Book of Flowgates (BOF), specifically the July 7, 2009 model posted at the OATI webFlowgate website (https://www.bof.oati.net/; load flow case: sum09idctr2p2_v30.zip and BOF: BOF_200907092130.uu)
- The 2009 FERC Form 715 filing Part 2 and 6 from various eastern interconnection regions – protected by FERC CEII-Consultant non-disclosure agreement (NDA).
- Publications posted at the Ontario – Independent System Operator website (http://www.ieso.ca/imoweb/pubs/marketReports/OntTxSystem_2009nov.pdf) – primarily, the "Ontario Transmission System" publication issued on November 17, 2009.
- Publications posted at the New York –Independent System Operator website (http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp) - primarily the 2009 Reliability Needs Assessment publication issued on January 13, 2009.
- DOE – Assessment of Historical Transmission Congestion in the Eastern Interconnection issued July 2009 (http://www.congestion09.anl.gov/documents/docs/EasternInterconnection.pdf).

Appendix F: Key MAPS Files

This appendix is provided as an informational cross-reference listing important MAPS filenames associated with the database discussed throughout this document.

Table F - 1 List of Key MAPS Files

File	Filename
MIF	EI_FC_FLT_V11.in05
EEI LOAD SHAPE FOLDER	EI-LOADS-EST-2007_INDAVER3YRS
EEI WIND SHAPE	WIND_EI_NREL2006new.eei
GT IN41 File 1	gt05202010.in41
LOADFLOW File 1	sum09idctr2p2_04272010_ceii.mgt
PRE CONTROL File	pre.ctl
GT CONTROL File 1	gt.ctl
MAPS CONTROL File 1	mai.ctl

6 *Appendix B* - GE-MAPS™ Brochure

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

GE Energy

MAPS™ Software - For Informed Economic Decisions

In the rapidly changing world of the electric power industry, one thing has remained constant – the need to accurately model the economic operation of the power system in order to make informed decisions. Whether your interest is in assessing the value of a portfolio of generating units or in identifying the transmission bottlenecks that most seriously constrain the economic operation of the system, you must capture the complex interaction between generation and transmission systems. GE Energy offers and supports the Multi Area Production Simulation Software program (MAPS), which provides the detailed modeling your business needs.

MAPS Modeling Detail

MAPS software integrates highly detailed representations of a system's load, generation, and transmission into a single simulation. This enables calculation of hourly production costs in light of the constraints imposed by the transmission system on the economic dispatch of generation.

Generation system data capabilities of MAPS include multi-step cost curves, unit cycling capabilities, emission characteristics, and market bids by unit loading block. The generation units, along with chronological hourly load profiles, are assigned to individual buses on the system.

The transmission system is modeled in terms of individual transmission lines, interfaces (which are groupings of lines), phase-angle regulators (PARs), and HVDC lines. Limits can be specified for the flow on the lines and interfaces and the operation of the PARs. MAPS software models voltage and stability considerations through operating nomograms that define how these limits can change hourly as a function of loads, generation, and flows elsewhere on the system.

Hourly load profiles are adjusted to meet peak and energy forecasts input to the model on a monthly or annual basis. Information on hourly loads at each bus in the system is required for MAPS to accurately calculate electrical flows on the transmission system. This is specified by assigning one, or a combination of several hourly load profiles to each load bus. In addition to studying all of the hours in the year, MAPS can be used to study all the days in the year on a bi-hourly basis, or a typical week per month on an hourly or bi-hourly basis. With these modeling options, MAPS simulates the loads in chronological order and does not sort them into load duration curves.

Based on this detailed representation of the entire system, MAPS performs a security-constrained dispatch of the generation by monitoring transmission system flows under both normal and contingency conditions.

Data for Informed Decisions

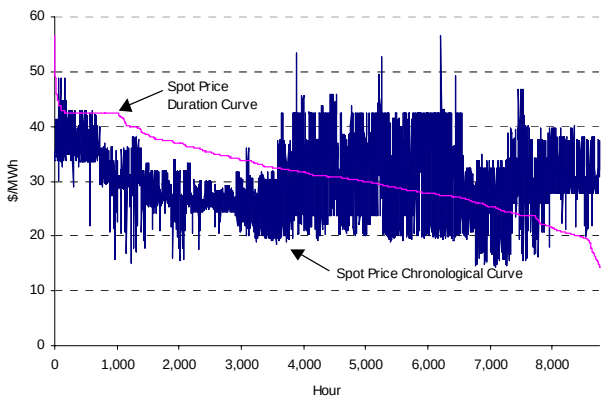
Making the right choices in today's environment requires increasingly more detailed information about the operation of the system. In addition to traditional production costing quantities of unit generation and costs, MAPS also provides the following data:

- Calculations of hour-by-hour, nodal or bus spot prices of energy.
- Calculations of hourly line flows and congestion costs.

Generation	Transmission	Loads	Transactions
– Detailed Representation – Secure Dispatch	– Tracks Individual Flows – Obeys Real Limits	– Chronological by Bus – Varying Losses	– Automatic Evaluation – LocationSpecific

MAPS Models the Bulk Power System

™MAPS is a Trademark of General Electric Company



Unit Bus Spot Price of Energy

- Determinations of unit revenues based on MW output and bus spot prices.
- Computations of hourly emission quantities and removal and trading costs.
- Identification of companies and generators responsible for power flows on lines.

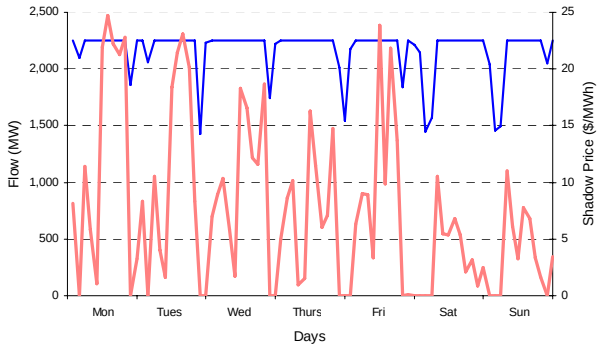
MAPS also ties to other software programs offered and supported by GE Energy, thus expanding its data analysis capabilities even further:

- MAPS ties to Positive Sequence Load Flow software (PSLF) to analyze the dispatch for a given hour for an accurate picture of voltage profile, var requirements, and system and area losses.
- MAPS ties to Multi Area Reliability Simulation software (MARS) to determine adequacy of installed capacity via Multi-Area Reliability Simulation.

MAPS Applications

Because of its detailed representation of generation and transmission systems, MAPS can be used to study a number of issues related to the deregulated utility market:

- The attributes of different proposed market structures and the development of pricing algorithms.
- The possibility of one or more market participant exerting market power.
- The value of a generation portfolio operating in a deregulated market.
- The location of transmission bottlenecks and associated congestion costs as well as transmission congestion contract (TCC) valuation.
- The impact on total system emissions that result from the addition of new generation.



Interface Flow and Shadow Price

Accurate Decisions Depend on Accurate Data

Your business depends on accurate modeling data for accurate decision-making. GE leverages more than 80 years of experience in analyzing the power industry's economics and equipment to provide you with the tools you need to run your business successfully. Contact the representative named below to find out more about how MAPS software and other services GE provides can help optimize your business strategies.

For more information on MAPS software contact

Devin T. Van Zandt
GE Energy
phone: 518-385-9066
email: devin.vanzandt@ge.com

http://www.gepower.com/energyconsulting

Copyright©2008 GE Energy. All rights reserved.
BROC10320 (2/02)

imagination at work

7 *Appendix C* - Indian Point Unit 2 Retirement Scenario Comparison

Tables 7.1 through 7.5 below compare the Base Case results from Section 3 (Indian Point Unit 2 operating license extension) against the Base Case results under the Indian Point Unit 2 Retirement Scenario in Section 4.

Table 7.1 Total Annual Load-Weighted Cost to Serve (M$) by Pool:

Indian Point Unit 2 Retirement Scenario Comparison

		2015	2016	2017	2018	2019	2020
Base Case (M$)	NE Pool	$ 8,215	$ 8,545	$ 8,856	$ 9,090	$ 9,709	$ 9,957
	NY Pool	$ 10,586	$ 11,086	$ 11,400	$ 11,704	$ 12,532	$ 12,842
	Ontario	$ 6,872	$ 7,485	$ 7,678	$ 8,085	$ 8,303	$ 8,635
	PJM	$ 43,081	$ 45,087	$ 45,209	$ 46,964	$ 49,922	$ 51,825
	TOTAL	$ 68,755	$ 72,203	$ 73,143	$ 75,843	$ 80,465	$ 83,259
Base Case w/ Indian Point Unit 2 Retirement (M$)	NE Pool	$ 8,262	$ 8,570	$ 8,912	$ 9,141	$ 9,759	$ 10,031
	NY Pool	$ 10,940	$ 11,431	$ 11,721	$ 12,053	$ 12,927	$ 13,260
	Ontario	$ 6,847	$ 7,492	$ 7,700	$ 8,091	$ 8,328	$ 8,637
	PJM	$ 43,357	$ 45,405	$ 45,384	$ 47,163	$ 50,074	$ 52,093
	TOTAL	$ 69,406	$ 72,897	$ 73,717	$ 76,447	$ 81,088	$ 84,022
Increase (Decrease) (M$)	NE Pool	$ 47	$ 25	$ 55	$ 51	$ 50	$ 75
	NY Pool	$ 354	$ 345	$ 322	$ 349	$ 395	$ 418
	Ontario	$ (26)	$ 6	$ 21	$ 6	$ 25	$ 3
	PJM	$ 276	$ 318	$ 176	$ 199	$ 153	$ 268
	TOTAL	$ 651	$ 694	$ 574	$ 605	$ 623	$ 763
% Increase (Decrease)	NE Pool	0.6%	0.3%	0.6%	0.6%	0.5%	0.7%
	NY Pool	3.3%	3.1%	2.8%	3.0%	3.2%	3.3%
	Ontario	(0.4%)	0.1%	0.3%	0.1%	0.3%	0.0%
	PJM	0.6%	0.7%	0.4%	0.4%	0.3%	0.5%
	TOTAL	0.9%	1.0%	0.8%	0.8%	0.8%	0.9%

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Table 7.2 Total Annual Energy Production (GWh) by Pool: Indian Point Unit 2 Retirement Scenario Comparison

		2015	2016	2017	2018	2019	2020
Base Case (GWh)	NE Pool	120,492	121,789	122,396	124,031	126,229	127,615
	NY Pool	148,035	149,226	153,738	156,701	158,174	163,212
	Ontario	143,708	144,511	144,216	144,244	144,654	144,829
	PJM	735,037	739,106	747,167	751,786	758,825	757,786
	TOTAL	1,147,272	1,154,633	1,167,517	1,176,762	1,187,881	1,193,441
Base Case w/ Indian Point Unit 2 Retirement (GWh)	NE Pool	121,512	122,774	123,449	125,113	127,217	128,676
	NY Pool	144,810	146,109	150,600	153,206	154,922	159,744
	Ontario	143,718	144,518	144,243	144,382	144,744	145,008
	PJM	737,154	741,074	749,241	753,912	760,895	759,867
	TOTAL	1,147,195	1,154,475	1,167,534	1,176,612	1,187,778	1,193,294
Increase (Decrease) (GWh)	NE Pool	1,020	985	1,053	1,082	988	1,061
	NY Pool	(3,225)	(3,118)	(3,137)	(3,496)	(3,252)	(3,468)
	Ontario	10	7	27	138	90	179
	PJM	2,117	1,968	2,074	2,125	2,070	2,081
	TOTAL	(77)	(158)	17	(151)	(104)	(147)
% Increase (Decrease)	NE Pool	0.8%	0.8%	0.9%	0.9%	0.8%	0.8%
	NY Pool	(2.2%)	(2.1%)	(2.0%)	(2.2%)	(2.1%)	(2.1%)
	Ontario	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
	PJM	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
	TOTAL	(0.0%)	(0.0%)	0.0%	(0.0%)	(0.0%)	(0.0%)

Table 7.3 Total Annual NOx Production (Tons) by Pool: Indian Point Unit 2 Retirement Scenario Comparison

		2015	2016	2017	2018	2019	2020
Base Case (Tons)	NE Pool	14,398	14,529	15,530	14,737	15,068	15,144
	NY Pool	26,254	26,788	27,677	26,998	27,916	27,926
	Ontario	2,102	2,133	2,106	2,100	2,080	2,096
	PJM	320,234	316,280	327,105	318,475	318,351	311,774
	TOTAL	362,988	359,730	372,417	362,310	363,415	356,941
Base Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	14,508	14,633	15,646	14,822	15,158	15,279
	NY Pool	27,315	27,841	28,502	27,948	28,884	28,855
	Ontario	2,100	2,132	2,102	2,103	2,079	2,098
	PJM	321,177	317,233	327,894	319,300	319,290	312,823
	TOTAL	365,100	361,839	374,144	364,173	365,411	359,055
Increase (Decrease) (Tons)	NE Pool	110	104	116	86	90	135
	NY Pool	1,062	1,053	825	949	968	928
	Ontario	(1)	(1)	(3)	3	(1)	2
	PJM	943	952	789	825	939	1,048
	TOTAL	2,113	2,108	1,727	1,862	1,996	2,114
% Increase (Decrease)	NE Pool	0.8%	0.7%	0.7%	0.6%	0.6%	0.9%
	NY Pool	4.0%	3.9%	3.0%	3.5%	3.5%	3.3%
	Ontario	(0.1%)	(0.0%)	(0.2%)	0.1%	(0.0%)	0.1%
	PJM	0.3%	0.3%	0.2%	0.3%	0.3%	0.3%
	TOTAL	0.6%	0.6%	0.5%	0.5%	0.5%	0.6%

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Table 7.4 Total Annual SO2 Production (Tons) by Pool: Indian Point Unit 2 Retirement Scenario Comparison

		2015	2016	2017	2018	2019	2020
Base Case (Tons)	NE Pool	75,077	75,905	83,425	76,414	77,512	78,309
	NY Pool	51,076	52,364	55,576	53,185	54,031	54,090
	Ontario	20,228	20,449	20,164	20,094	19,668	19,898
	PJM	1,807,060	1,756,709	1,795,020	1,743,189	1,730,725	1,674,074
	TOTAL	1,953,440	1,905,428	1,954,186	1,892,882	1,881,936	1,826,370
Base Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	75,733	76,545	83,994	76,769	77,866	79,001
	NY Pool	52,242	53,650	56,392	54,168	54,933	55,053
	Ontario	20,205	20,431	20,118	20,074	19,623	19,851
	PJM	1,811,431	1,761,710	1,799,974	1,747,856	1,735,674	1,678,548
	TOTAL	1,959,611	1,912,336	1,960,477	1,898,866	1,888,096	1,832,453
Increase (Decrease) (Tons)	NE Pool	656	640	568	355	355	693
	NY Pool	1,166	1,285	816	983	902	963
	Ontario	(23)	(18)	(46)	(21)	(45)	(47)
	PJM	4,371	5,001	4,954	4,667	4,949	4,475
	TOTAL	6,171	6,908	6,291	5,984	6,160	6,084
% Increase (Decrease)	NE Pool	0.9%	0.8%	0.7%	0.5%	0.5%	0.9%
	NY Pool	2.3%	2.5%	1.5%	1.8%	1.7%	1.8%
	Ontario	(0.1%)	(0.1%)	(0.2%)	(0.1%)	(0.2%)	(0.2%)
	PJM	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%
	TOTAL	0.3%	0.4%	0.3%	0.3%	0.3%	0.3%

Table 7.5 Total Annual CO2 Production (Tons) by Pool: Indian Point Unit 2 Retirement Scenario Comparison

		2015	2016	2017	2018	2019	2020
Base Case (Tons)	NE Pool	43,129,318	43,086,285	44,978,154	44,289,028	44,835,766	45,601,366
	NY Pool	43,479,260	43,781,477	45,125,219	44,716,534	46,314,790	46,331,325
	Ontario	9,320,627	9,541,108	9,440,267	9,427,543	9,548,769	9,557,390
	PJM	426,452,174	424,264,527	432,499,292	427,210,980	427,827,876	419,341,384
	TOTAL	522,381,380	520,673,397	532,042,932	525,644,086	528,527,200	520,831,466
Base Case w/ Indian Point Unit 2 Retirement (Tons)	NE Pool	43,595,529	43,536,684	45,441,151	44,765,693	45,263,246	46,082,928
	NY Pool	45,955,876	46,180,994	47,356,204	47,068,064	48,517,082	48,376,677
	Ontario	9,322,668	9,542,984	9,441,215	9,483,667	9,577,454	9,625,816
	PJM	427,776,195	425,569,214	433,779,988	428,523,674	429,133,279	420,652,703
	TOTAL	526,650,267	524,829,876	536,018,557	529,841,098	532,491,060	524,738,124
Increase (Decrease) (Tons)	NE Pool	466,211	450,399	462,997	476,665	427,480	481,562
	NY Pool	2,476,615	2,399,516	2,230,984	2,351,530	2,202,292	2,045,352
	Ontario	2,041	1,876	948	56,124	28,685	68,426
	PJM	1,324,021	1,304,688	1,280,696	1,312,694	1,305,403	1,311,319
	TOTAL	4,268,888	4,156,479	3,975,626	4,197,012	3,963,860	3,906,658
% Increase (Decrease)	NE Pool	1.1%	1.0%	1.0%	1.1%	1.0%	1.1%
	NY Pool	5.7%	5.5%	4.9%	5.3%	4.8%	4.4%
	Ontario	0.0%	0.0%	0.0%	0.6%	0.3%	0.7%
	PJM	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
	TOTAL	0.8%	0.8%	0.7%	0.8%	0.7%	0.8%

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.

Proprietary and Confidential Information – Do not copy without written consent from GE Energy.