APPENDIX D
MODELING OF OUT-OF-STATE GENERATION AND LOAD

This appendix contains information on the modeling of generation capacity and electric loads in the areas outside of Illinois. In the EMCAS model, the representation of generation capacity and loads outside of Illinois was simplified. While all generating units operating within Illinois were modeled individually, out-of-state generation was modeled using aggregate production cost curves. These production cost curves, or so-called supply curves, represent generating units independent of ownership and show the cost of electricity generation as a function of the total power output. The electricity generation cost from out-of-state suppliers can be directly determined from the production cost curve as a value that corresponds to the level of power output.

The equivalent network of out-of-state areas (see Section 3.3 of the main report) included a number of control areas ranging from the Northern States Power Company (NSP – now Xcel Energy) in the northwest, to the Associated Electric Cooperative (AECI) in the southwest, to the Tennessee Valley Authority (TVA) in the southeast, to the Consumers Energy (CSU) and American Electric Power (AEP) areas in the east, and all of the large Wisconsin utilities in the north. A total of 24 out-of-state generation companies and their corresponding supply curves were included in the EMCAS simulation. The names and abbreviations of out-of-state generation companies are as follows:

1.	AECI	Associated Electric Cooperative
2.	AEP	American Electric Power
3.	ALTE	Alliant Energy (East)
4.	ALTW	Alliant Energy (West)
5.	Ameren-Out	Ameren (areas outside of Illinois)
6.	BREC	Big Rivers Electric Corporation
7.	CIN	Cinergy Corporation
8.	CONS	Consumers Energy
9.	DPC	Dairyland Power Cooperative
10.	DPL	Dayton Power & Light
11.	HE	Hoosier Energy
12.	IPL	Indianapolis Power & Light Company
13.	LGEE	LG&E Energy
14.	MEC	MidAmerican Energy Company
15.	MGE	Madison Gas and Electric Company
16.	MPW	Muscatine Power and Water
17.	NIPS	Northern Indiana Public Service Company
18.	NSP	Northern States Power Company (Xcel Energy)
19.	OVEC	Ohio Valley Electric Corporation
20.	SIGE	Southern Indiana Gas & Electric Company
21.	TVA	Tennessee Valley Authority
22.	UPPC	Upper Peninsula Power Company
23.	WEC	Wisconsin Energy Corporation
24.	WPS	Wisconsin Public Service Corporation

Hourly load profiles for the analysis year for the out-of-state areas were developed based on the same FERC Form 714 projections used for the Illinois companies. The load forecasts, developed on a control area basis, were aggregated into the same nodes used for the generation

companies. Thus, each out-of-state connection point had both load and generation associated with it.

One of the assumptions for the PowerWorld and EMCAS analyses was that out-of-state companies would actively participate in the same electricity market as the in-state companies. This included both sales and purchases of electric power. For the production cost case, it was assumed that electric power in out-of-state areas was generated on a production cost basis, according to the supply curves for out-of-state generation companies. In other scenarios, out-of-state companies were allowed to deviate from the production cost-based bidding and, in some cases, to apply strategic bidding.

In principle, an excess of available power in the out-of-state areas could be offered and sold in the Illinois electricity market if the price was lower than that of other competitors. In the same manner, the out-of-state demand companies were allowed to purchase power from the Illinois market if the price was lower than what was available from other sources. In both cases, the constraints imposed by the available transfer capabilities of transmission lines connecting Illinois with the out-of-state areas were strictly observed.

The following figures show the generation supply curves and the hourly load curves used for each of the out-of-state areas.

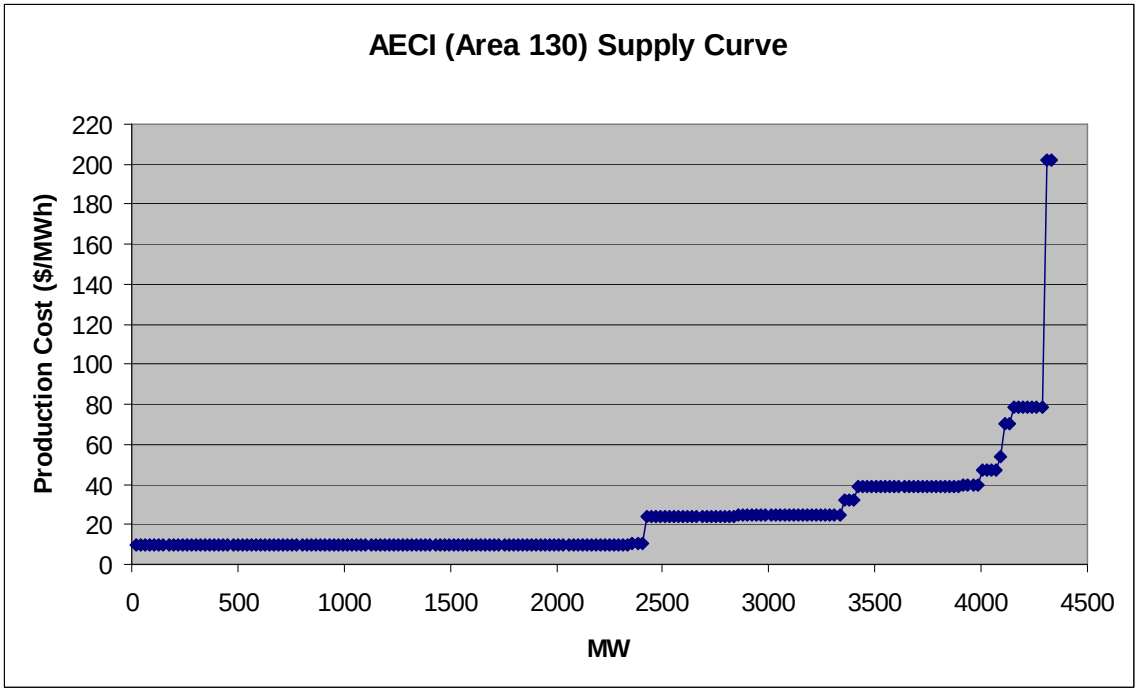

Figure D-1 AECI Generation Supply Curve

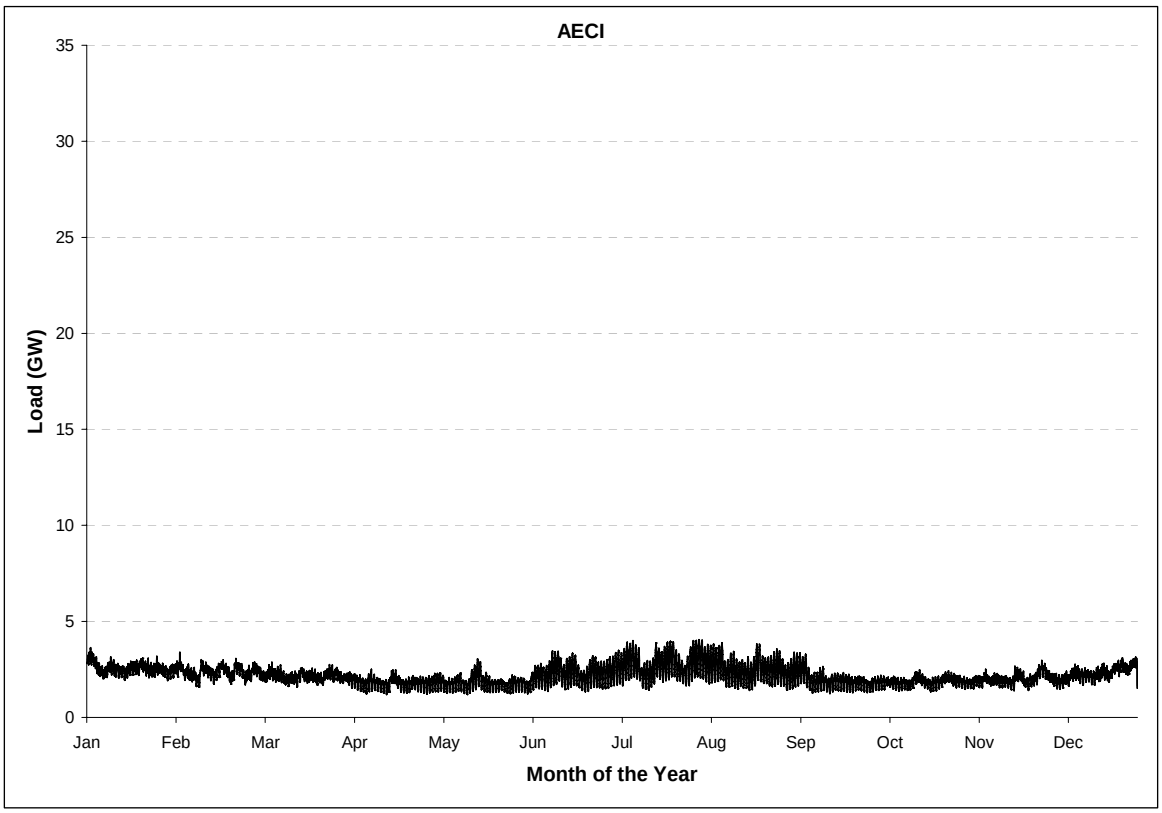

Figure D-2 AECI Load Curve

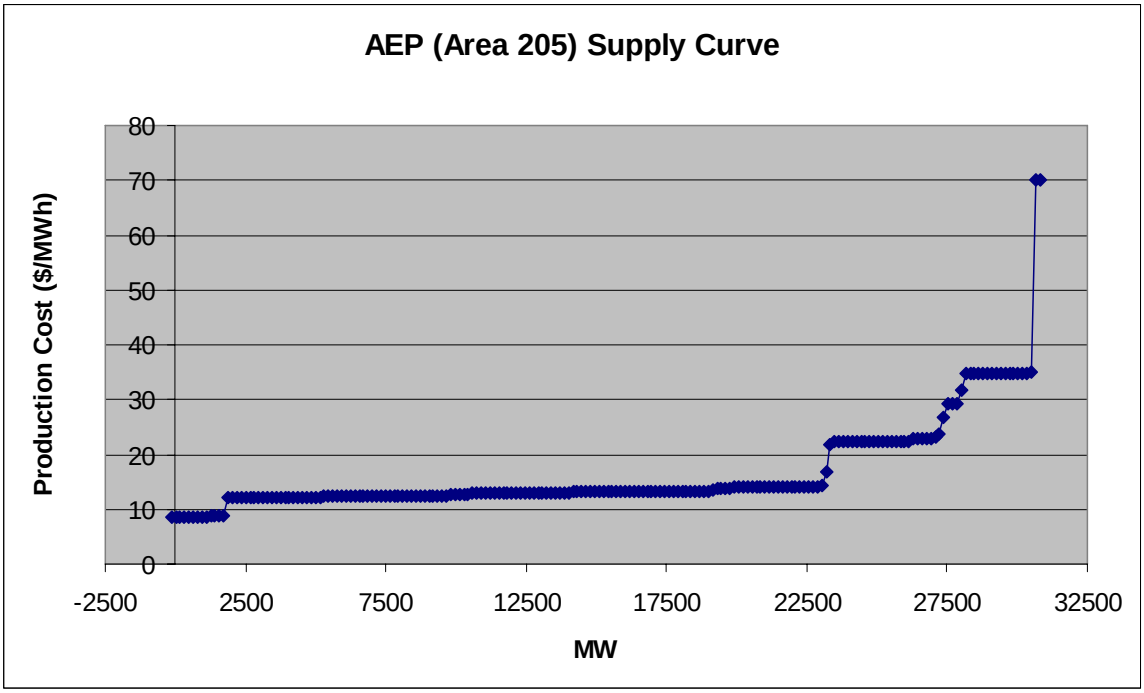

Figure D-3 AEP Generation Supply Curve

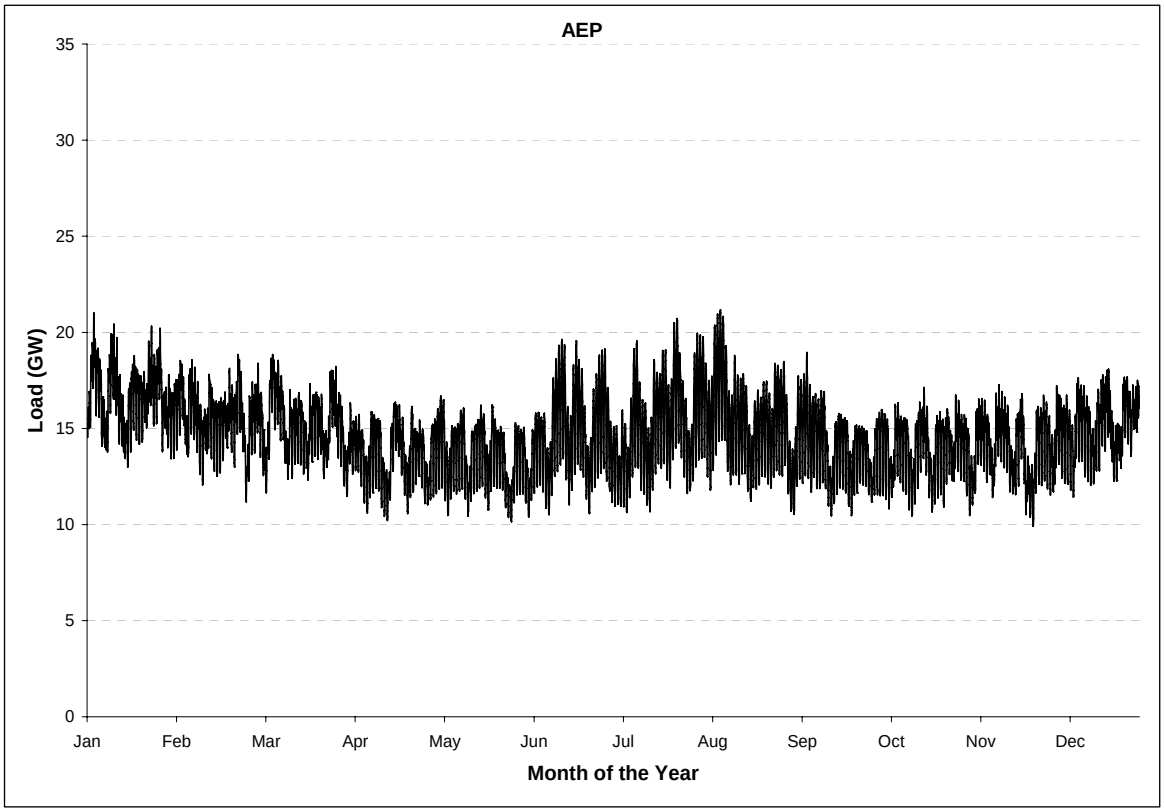

Figure D-4 AEP Load Curve

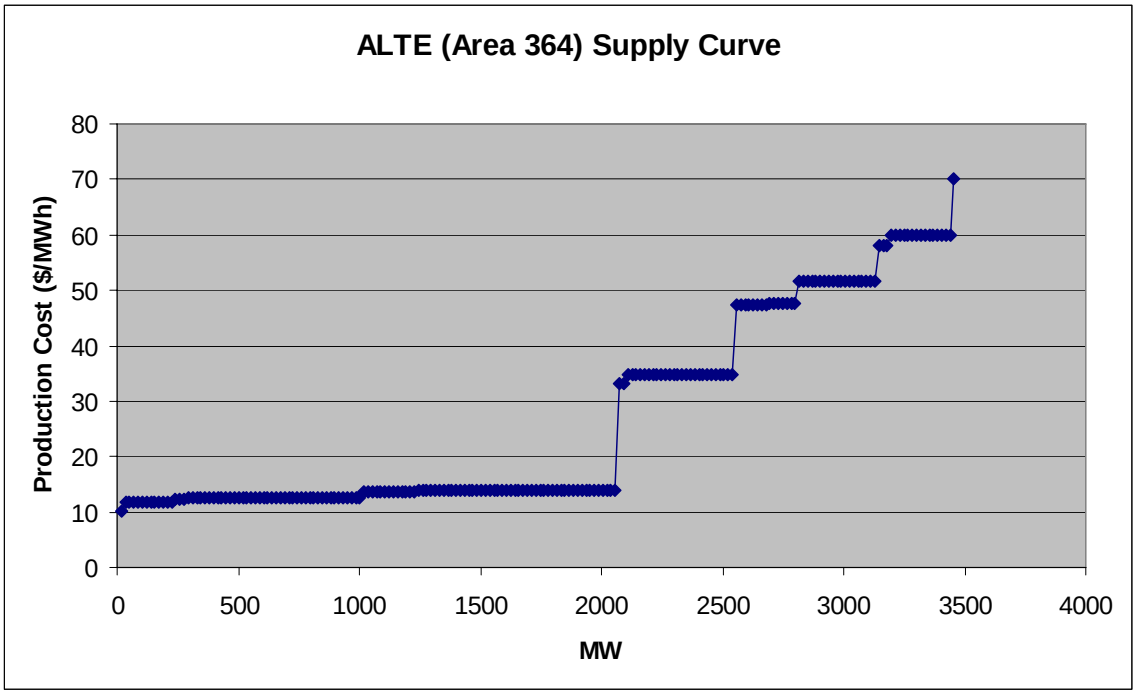

Figure D-5 ALTE Generation Supply Curve

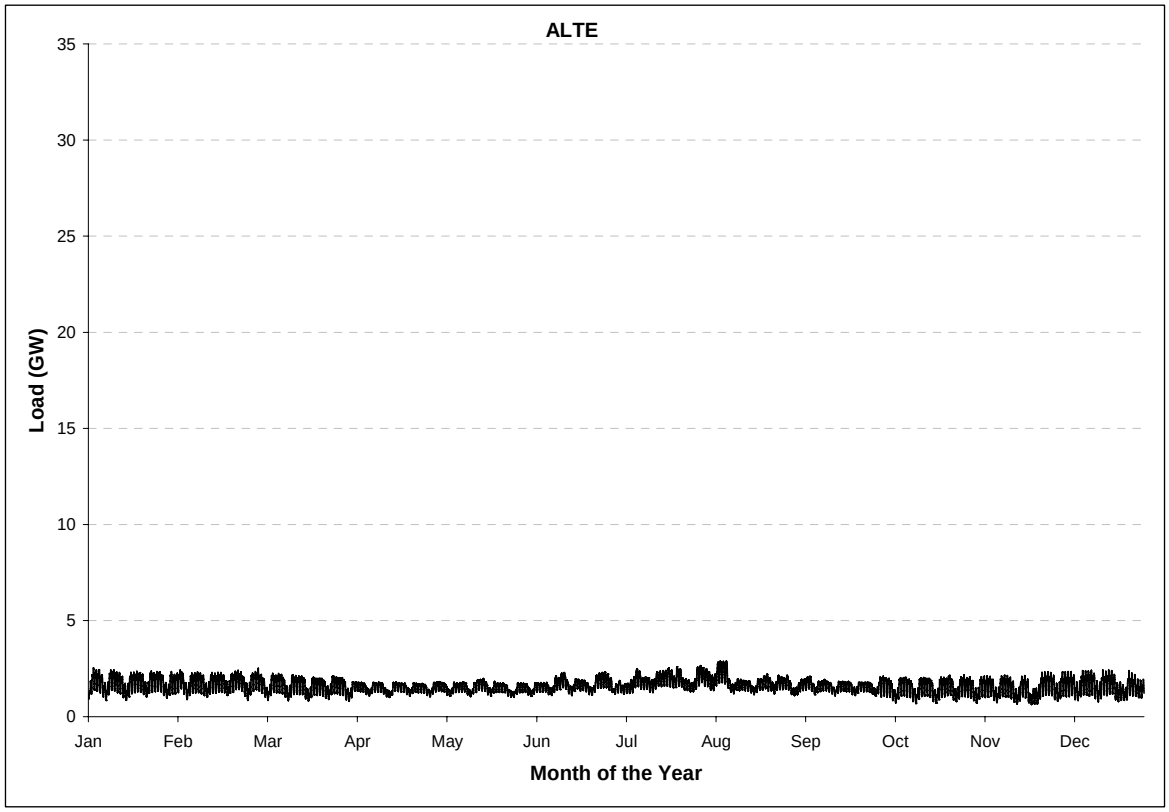

Figure D-6 ALTE Load Curve

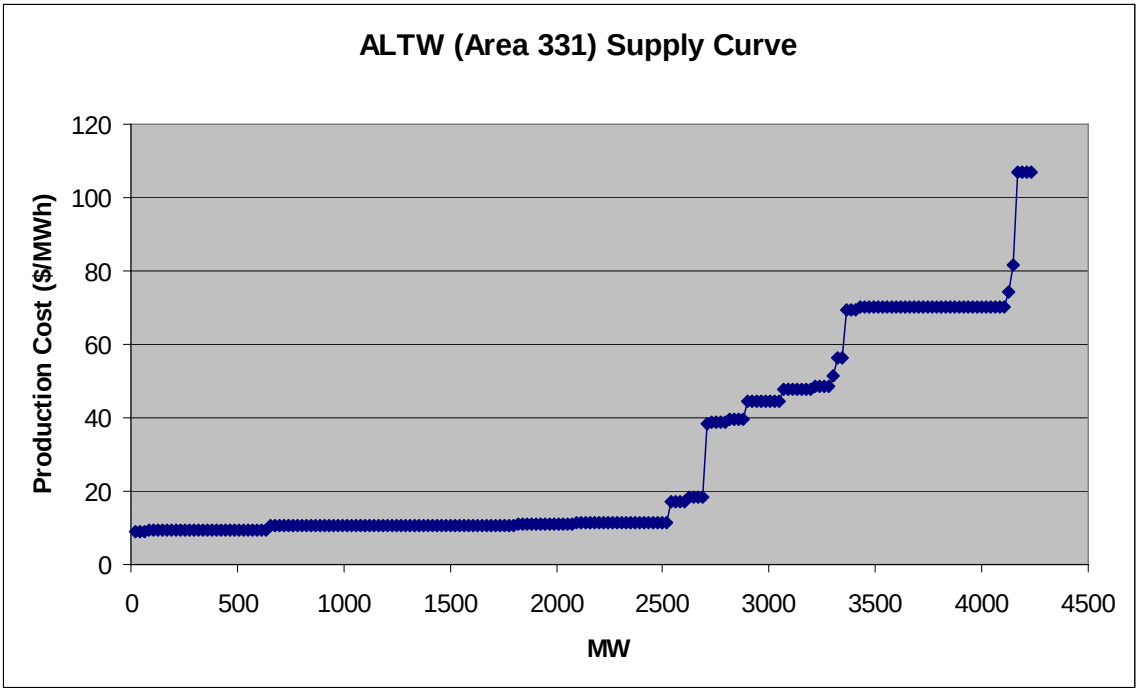

Figure D-7 ALTW Generation Supply Curve

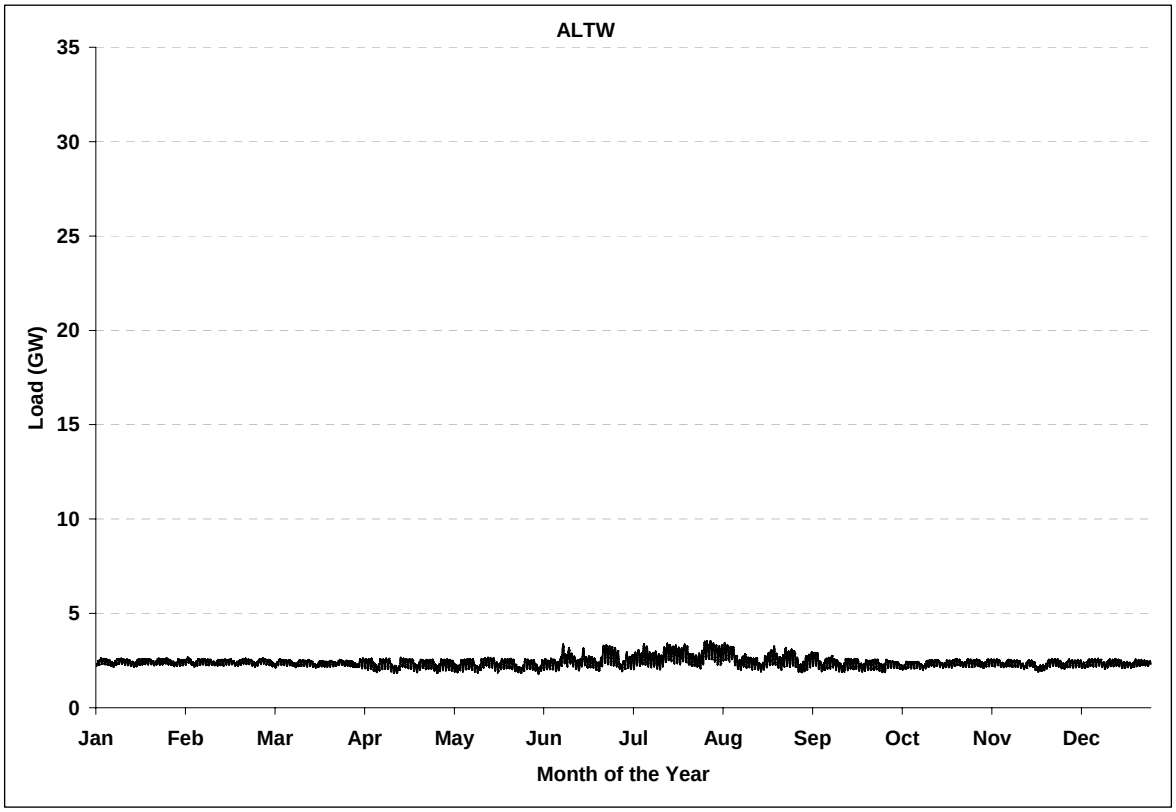

Figure D-8 ALTW Load Curve

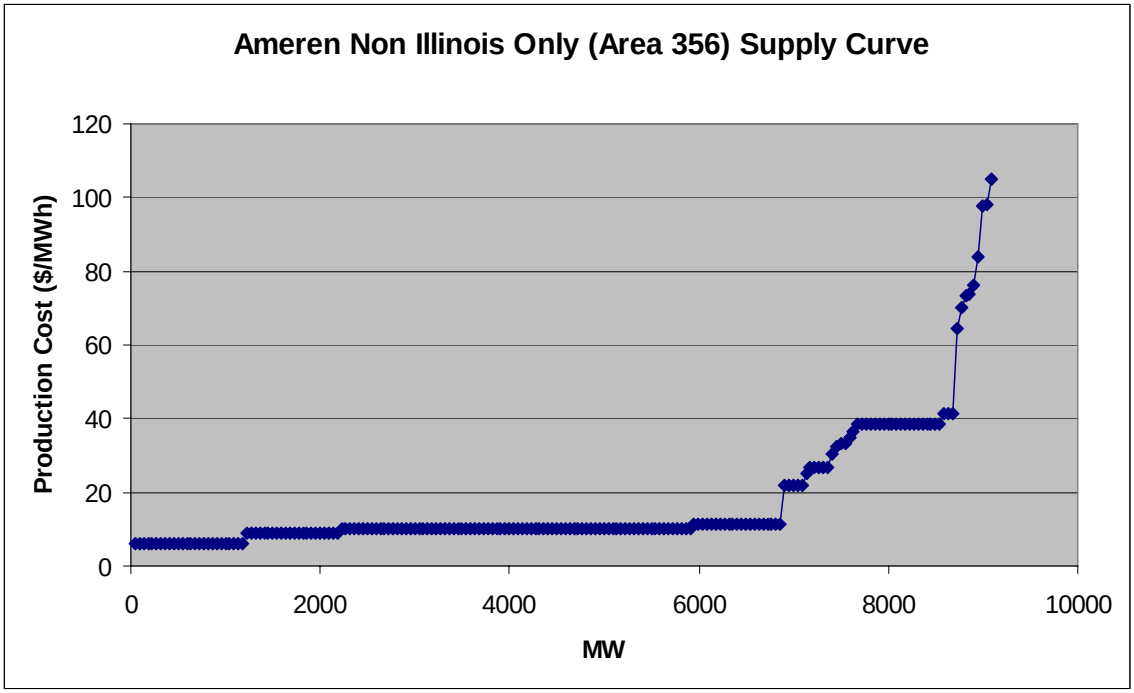

Figure D-9 Ameren Out Generation Supply Curve

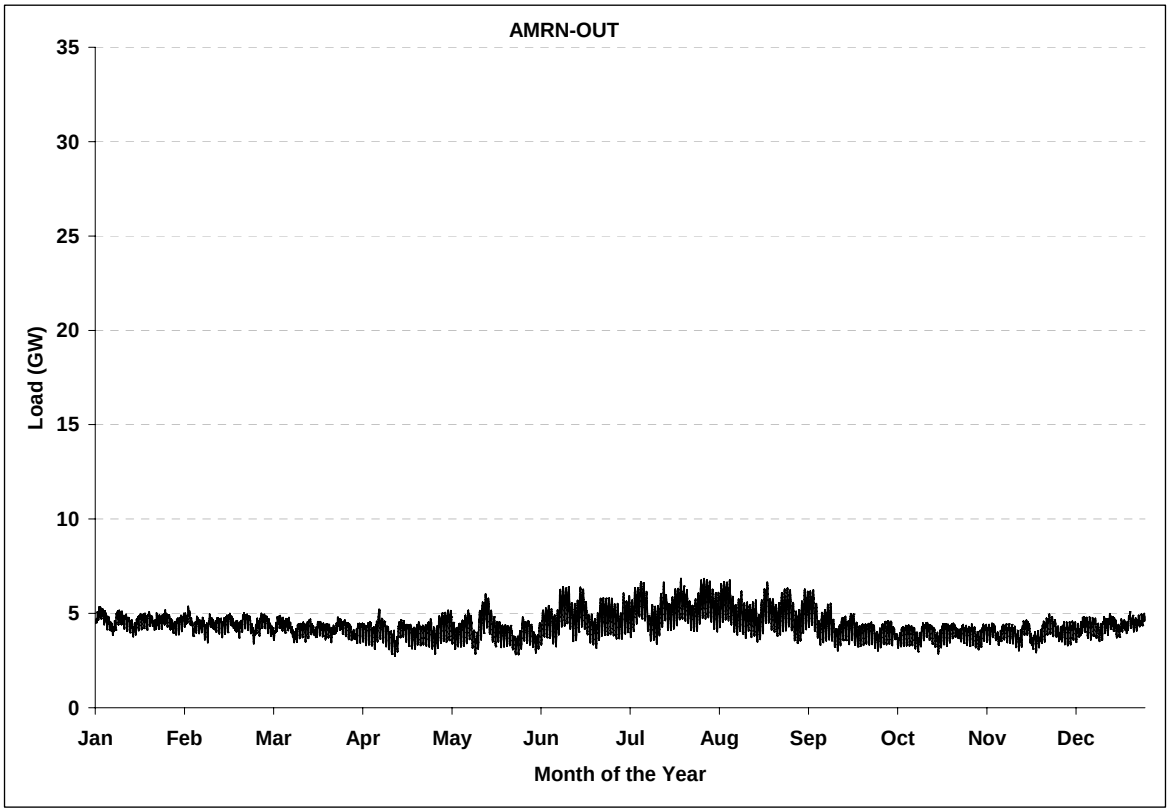

Figure D-10 Ameren Out Load Curve

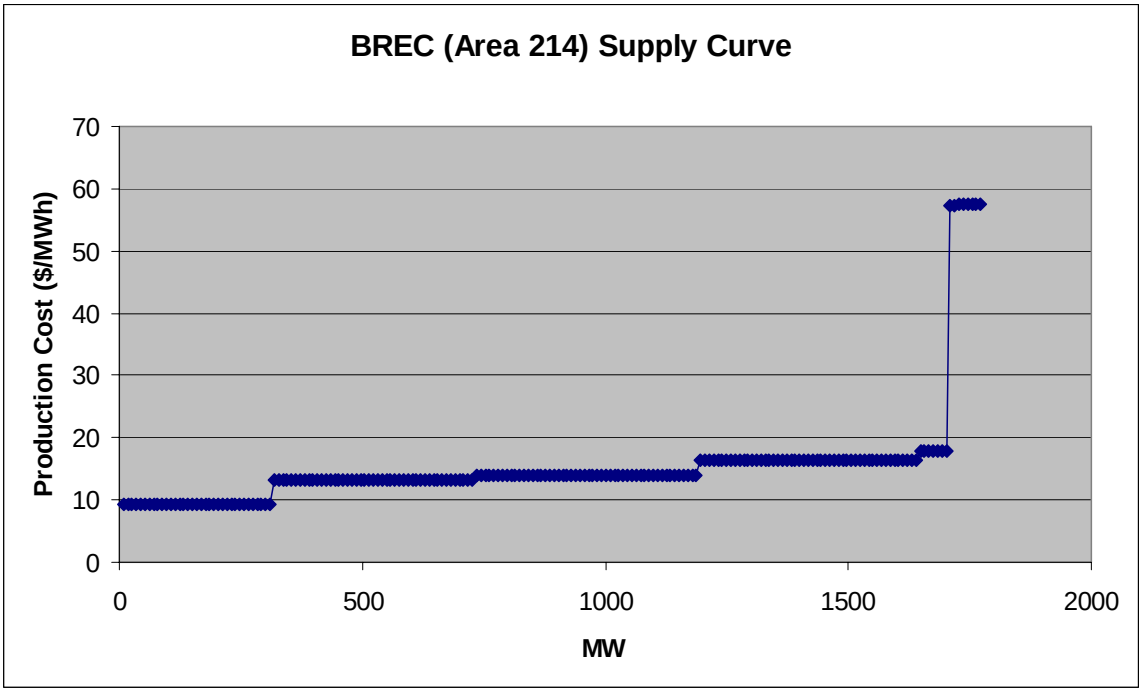

Figure D-11 BREC Generation Supply Curve

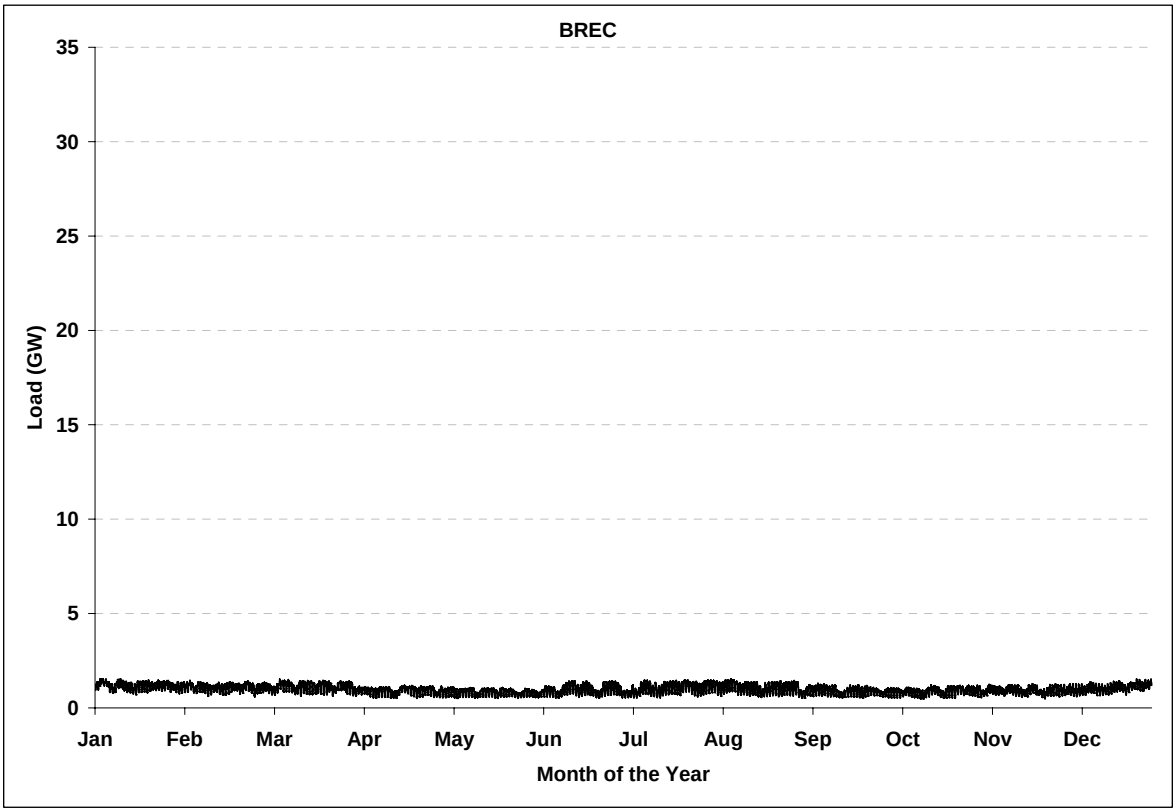

Figure D-12 BREC Load Curve

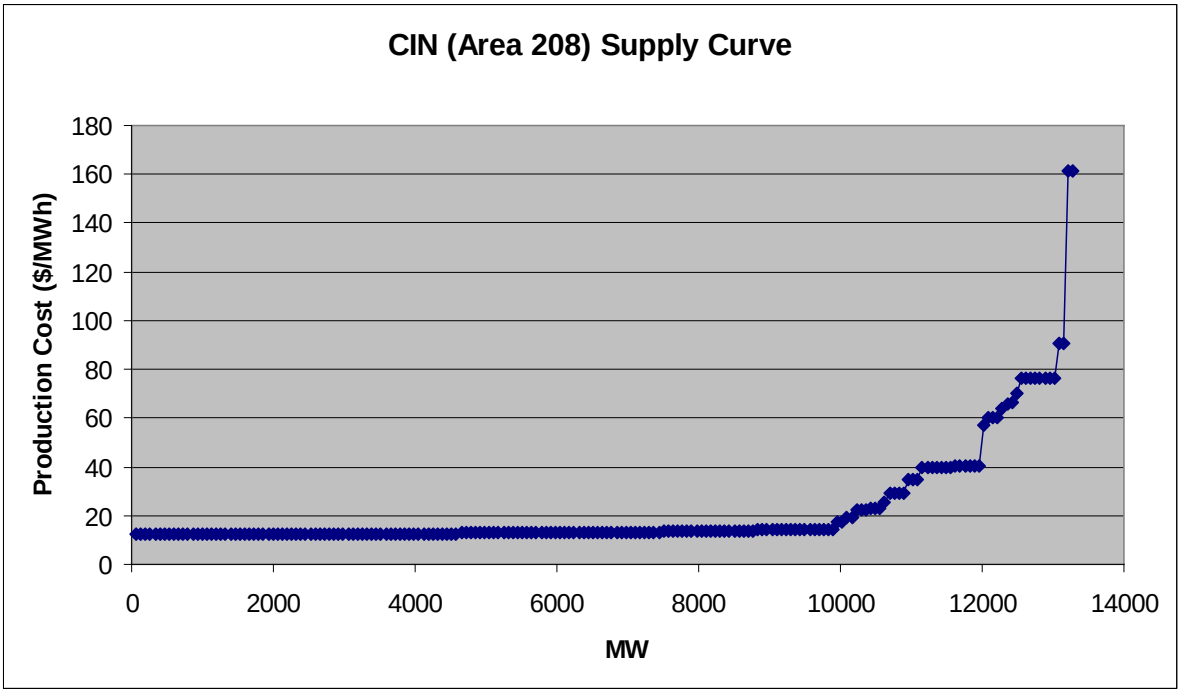

Figure D-13 CIN Generation Supply Curve

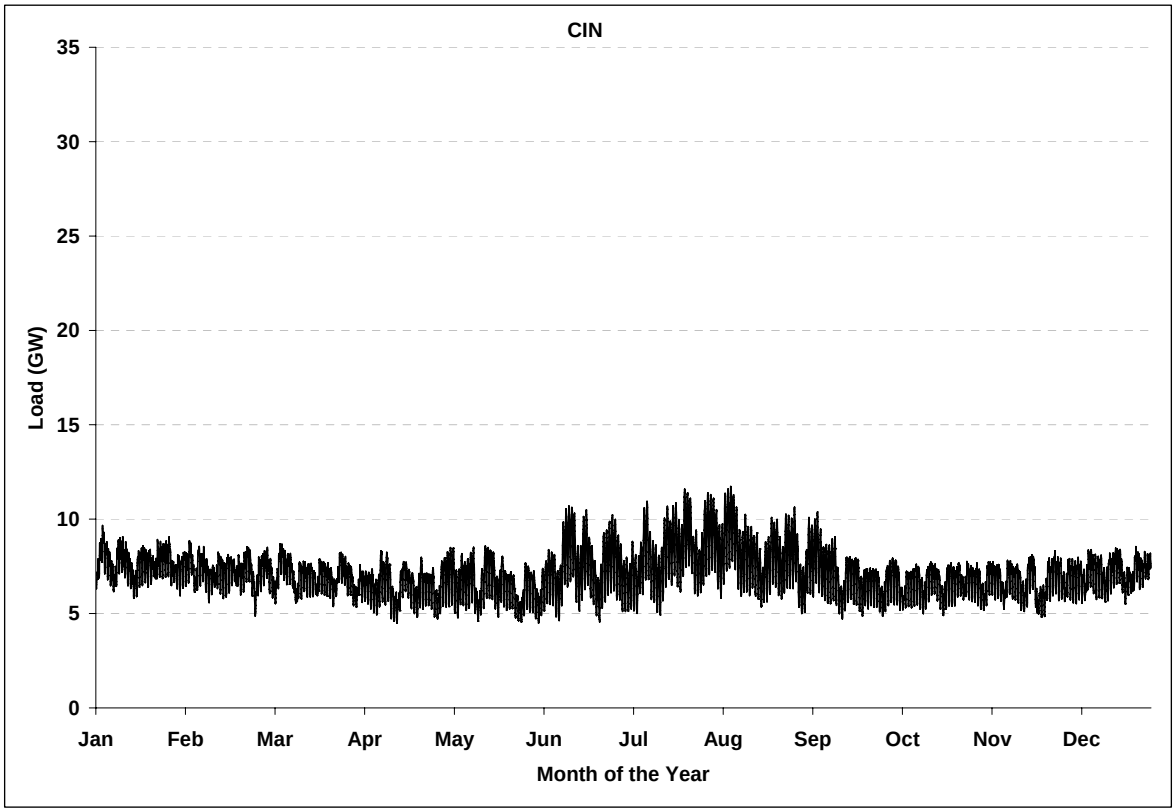

Figure D-14 CIN Load Curve

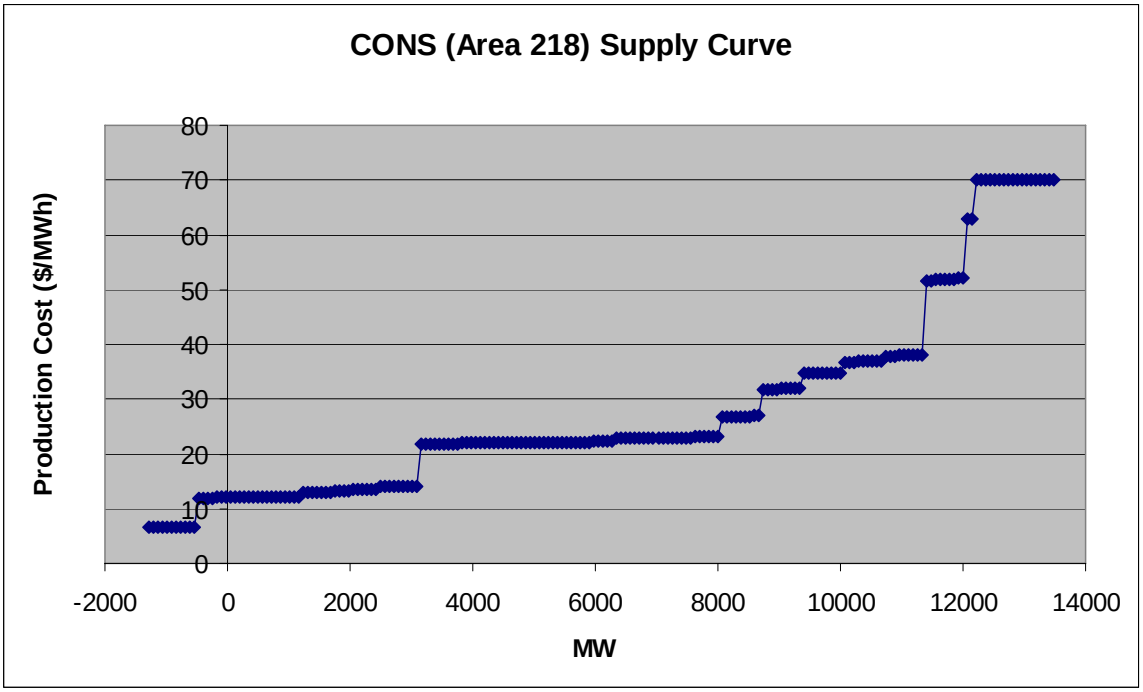

Figure D-15 CONS Generation Supply Curve

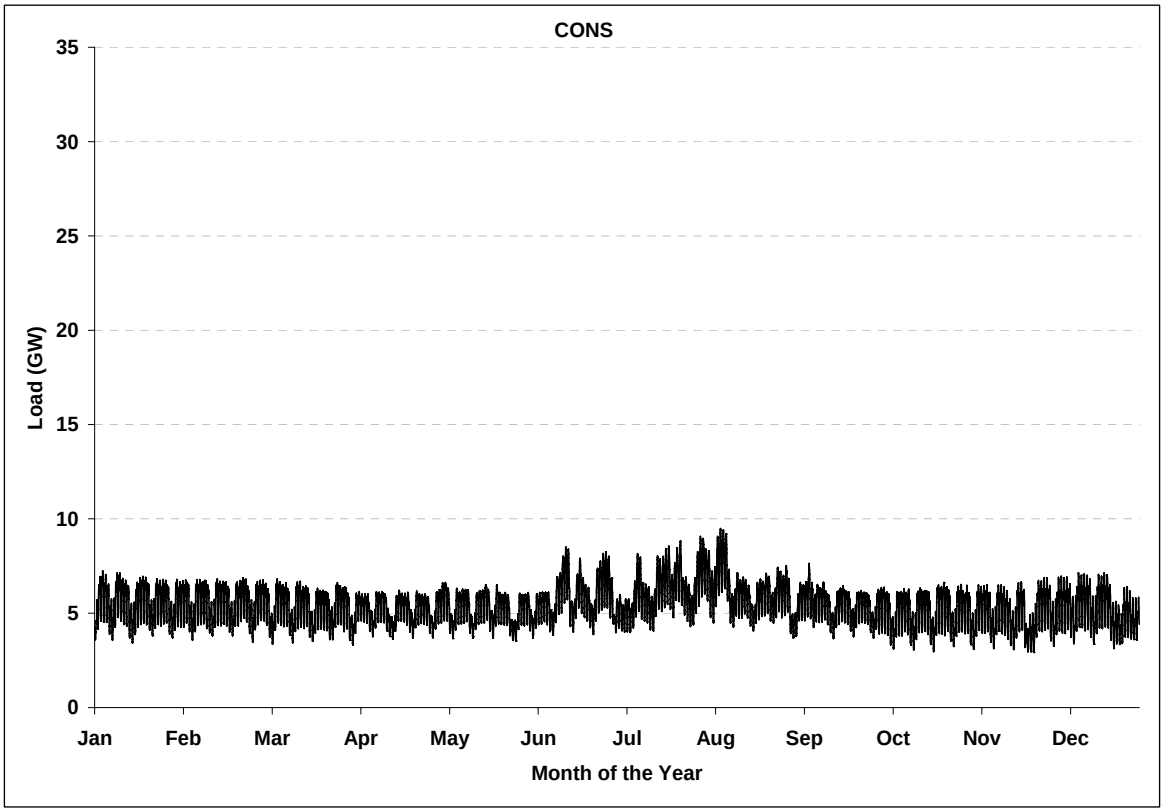

Figure D-16 CONS Load Curve

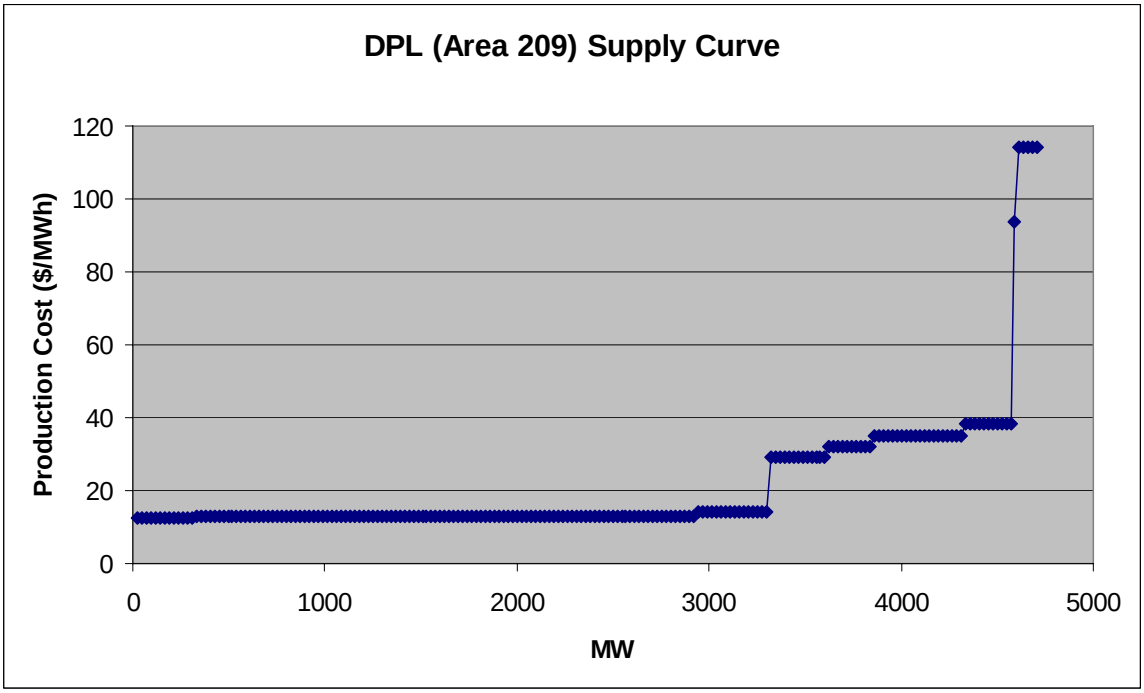

Figure D-17 DPL Generation Supply Curve

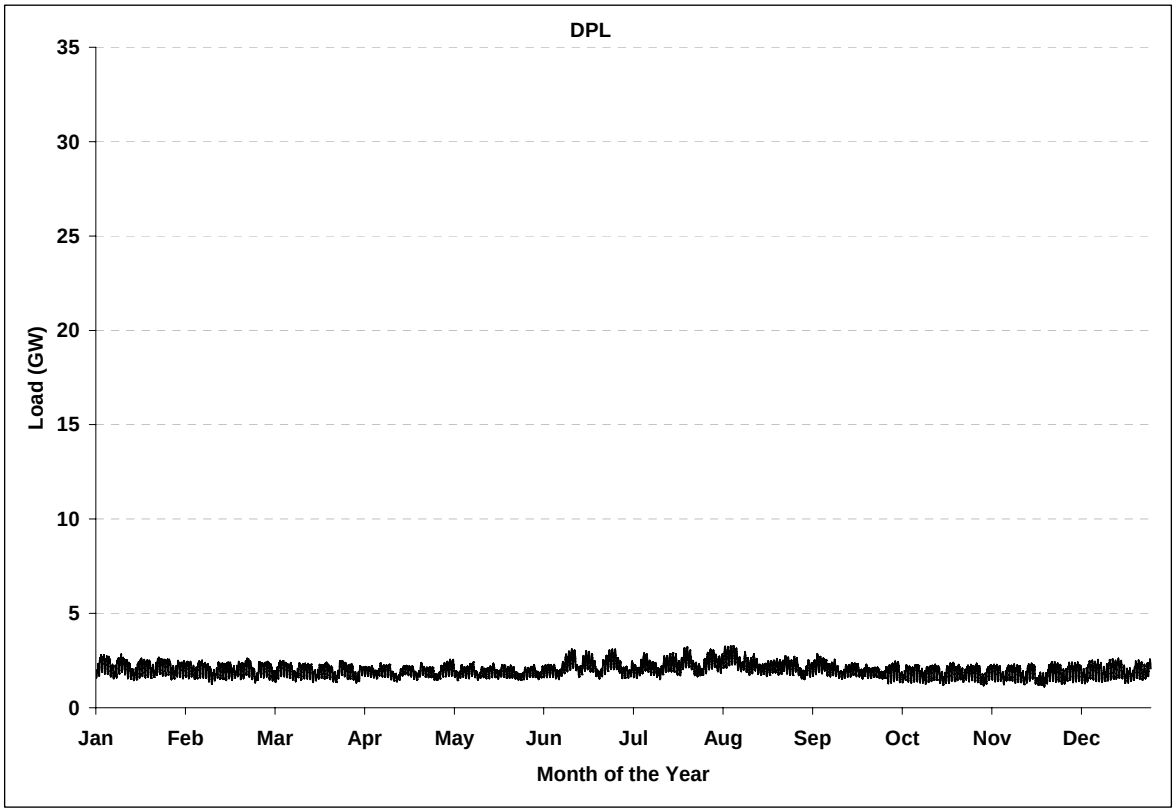

Figure D-18 DPL Load Curve

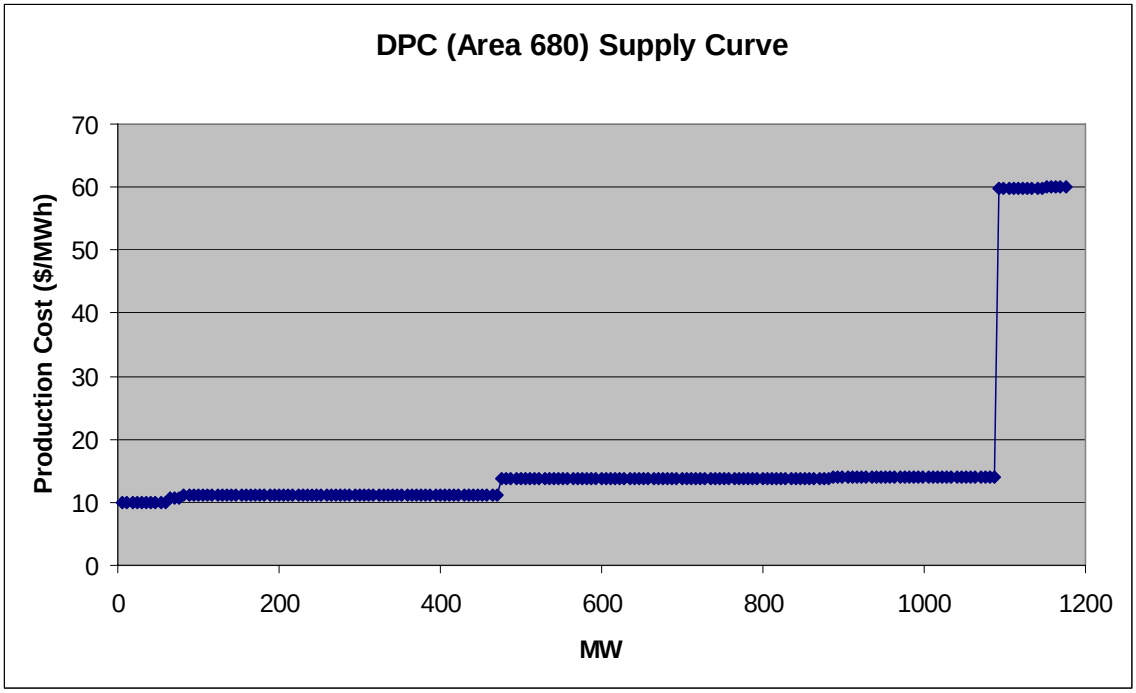

Figure D-19 DPC Generation Supply Curve

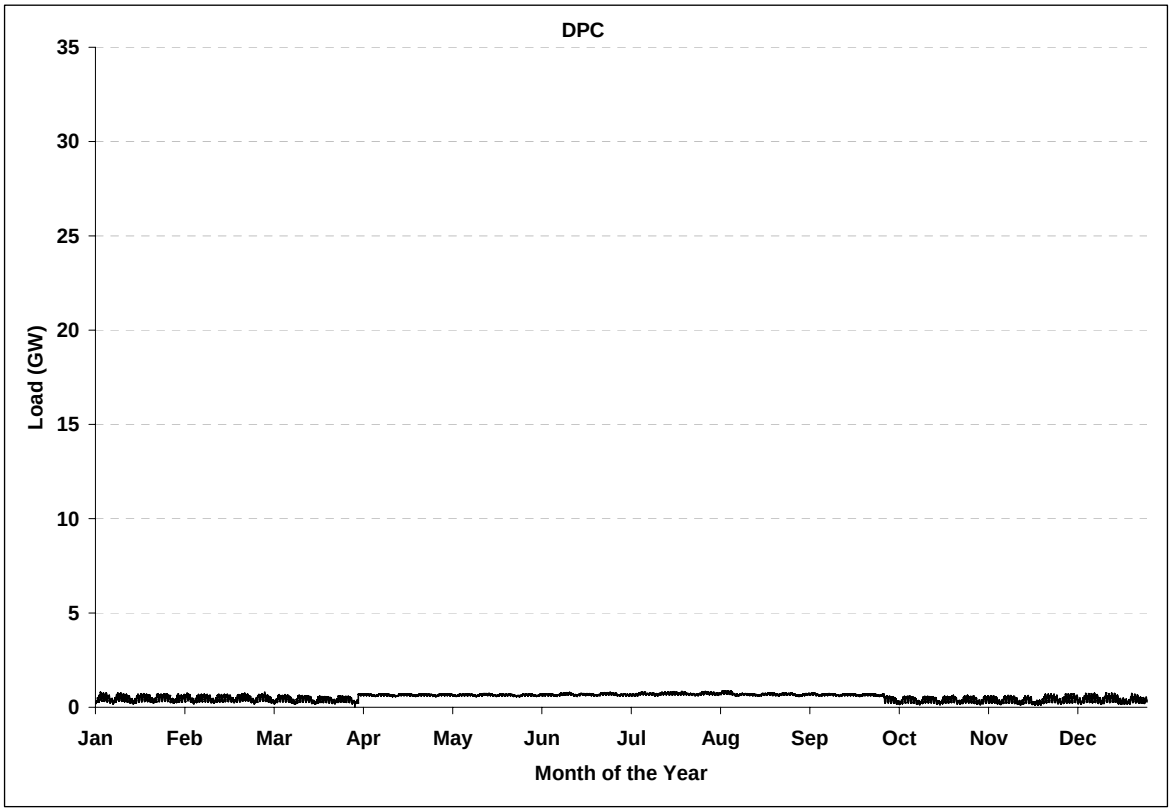

Figure D-20 DPC Load Curve

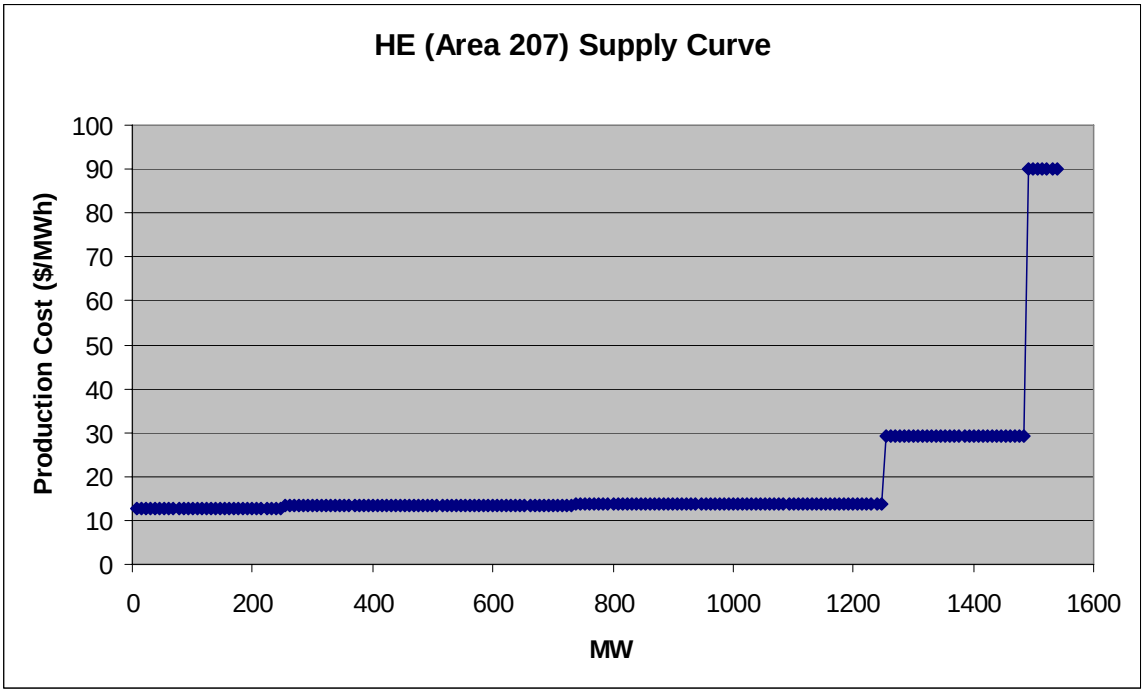

Figure D-21 HE Generation Supply Curve

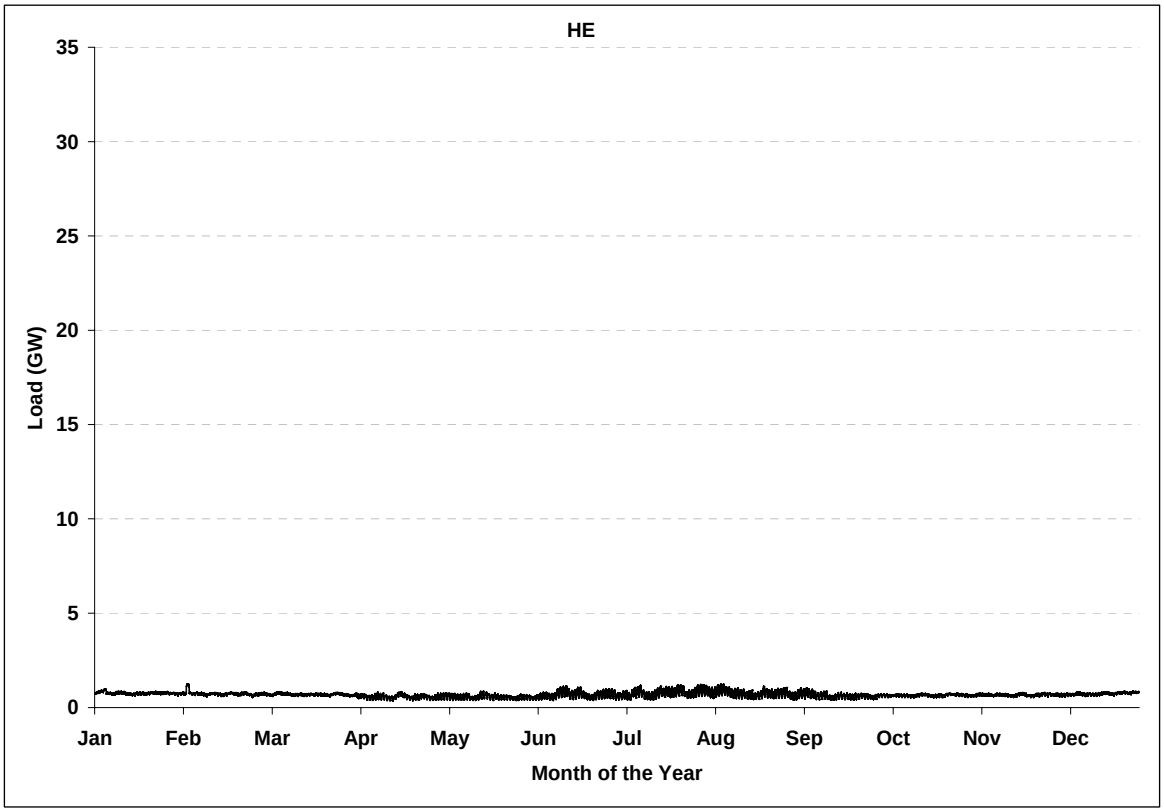

Figure D-22 HE Load Curve

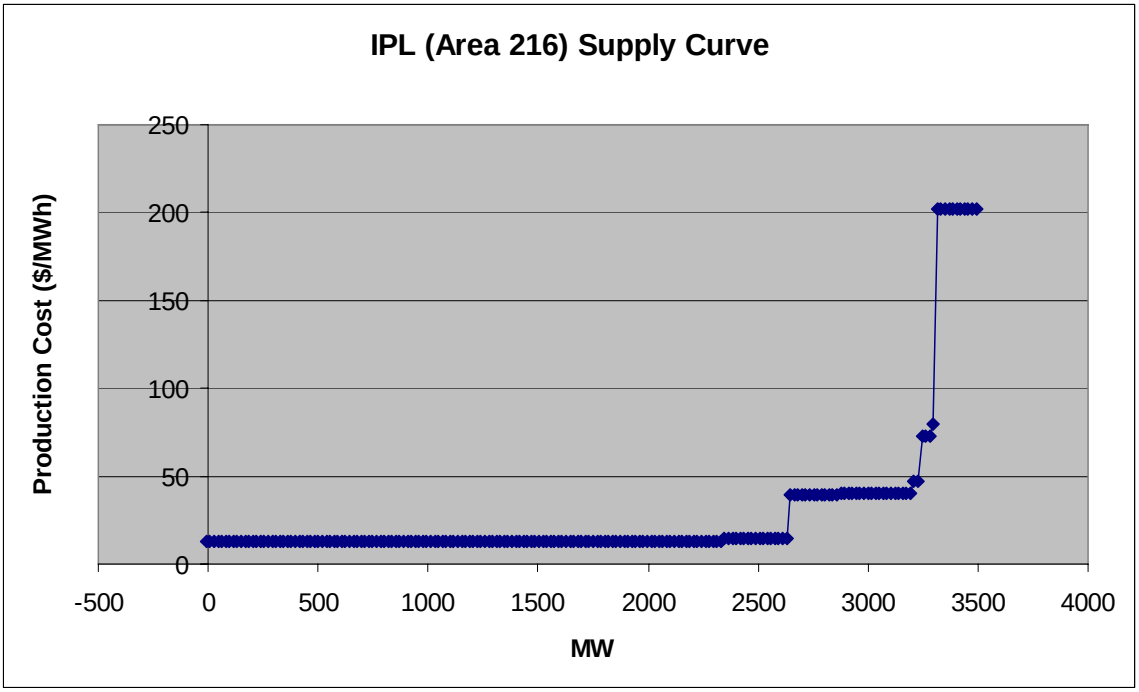

Figure D-23 IPL Generation Supply Curve

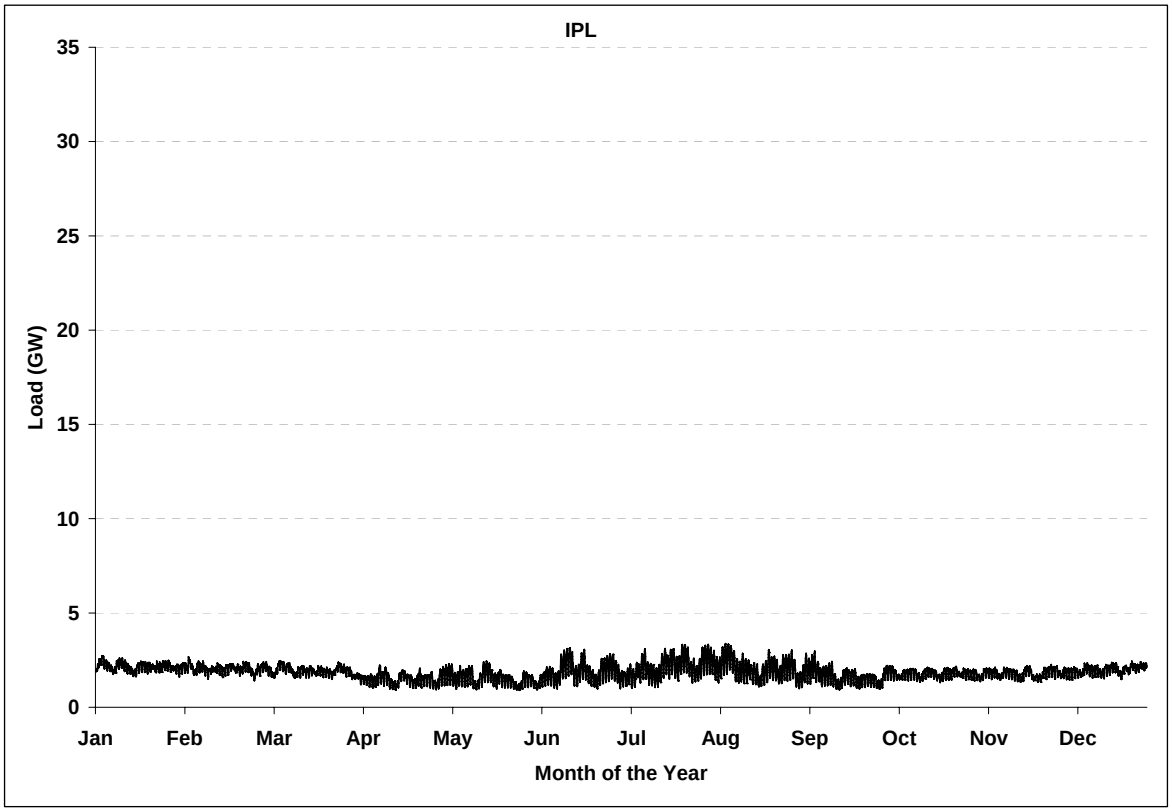

Figure D-24 IPL Load Curve

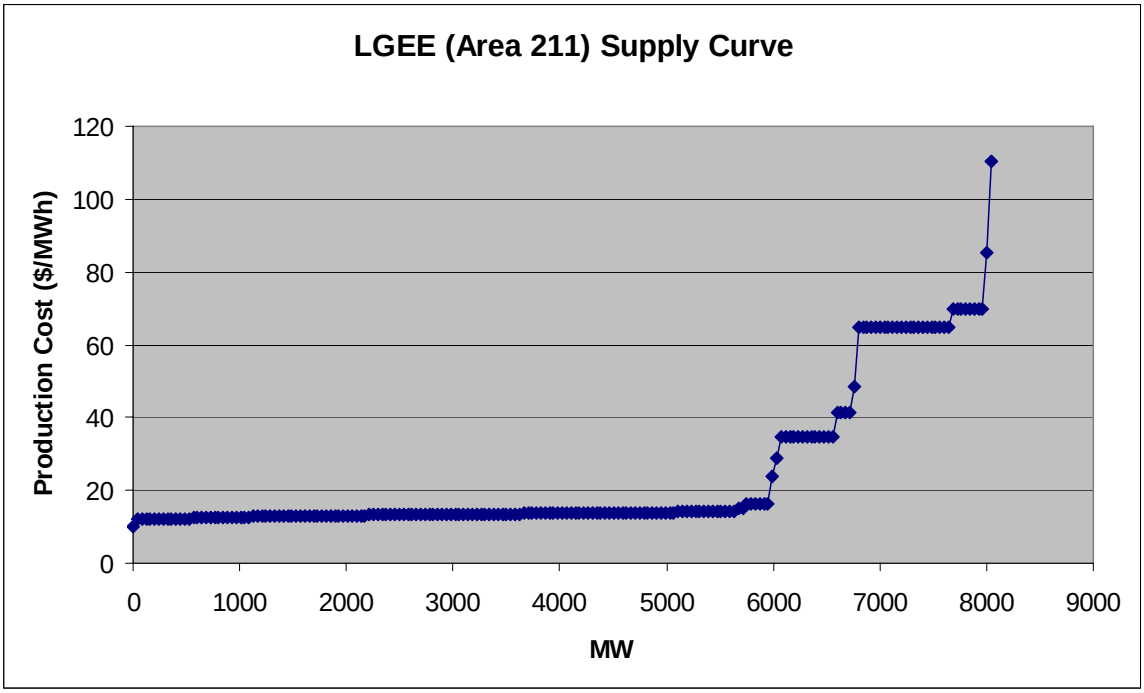

Figure D-25 LGEE Generation Supply Curve

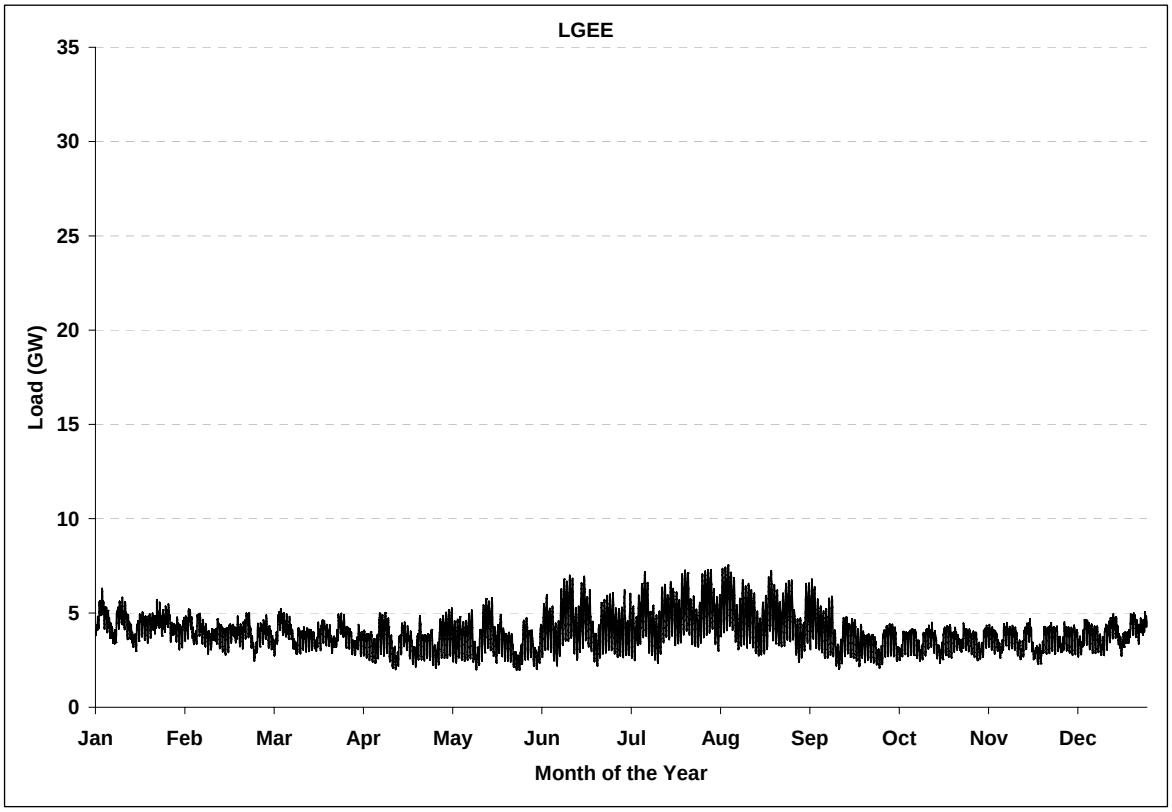

Figure D-26 LGEE Load Curve

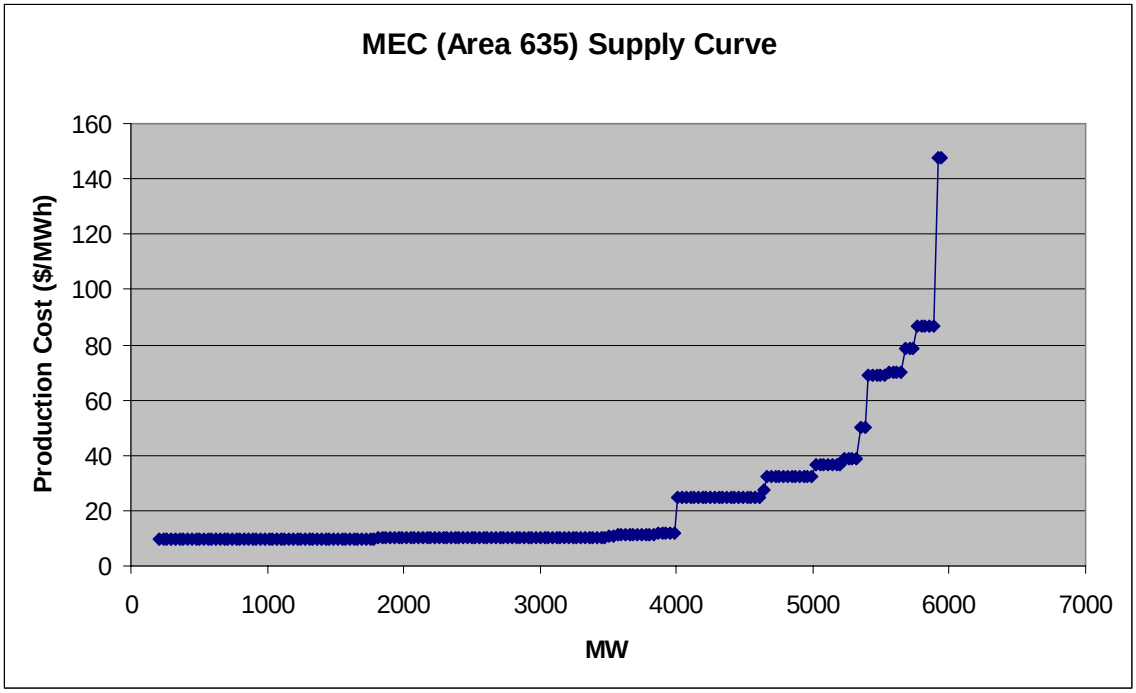

Figure D-27 MEC Generation Supply Curve

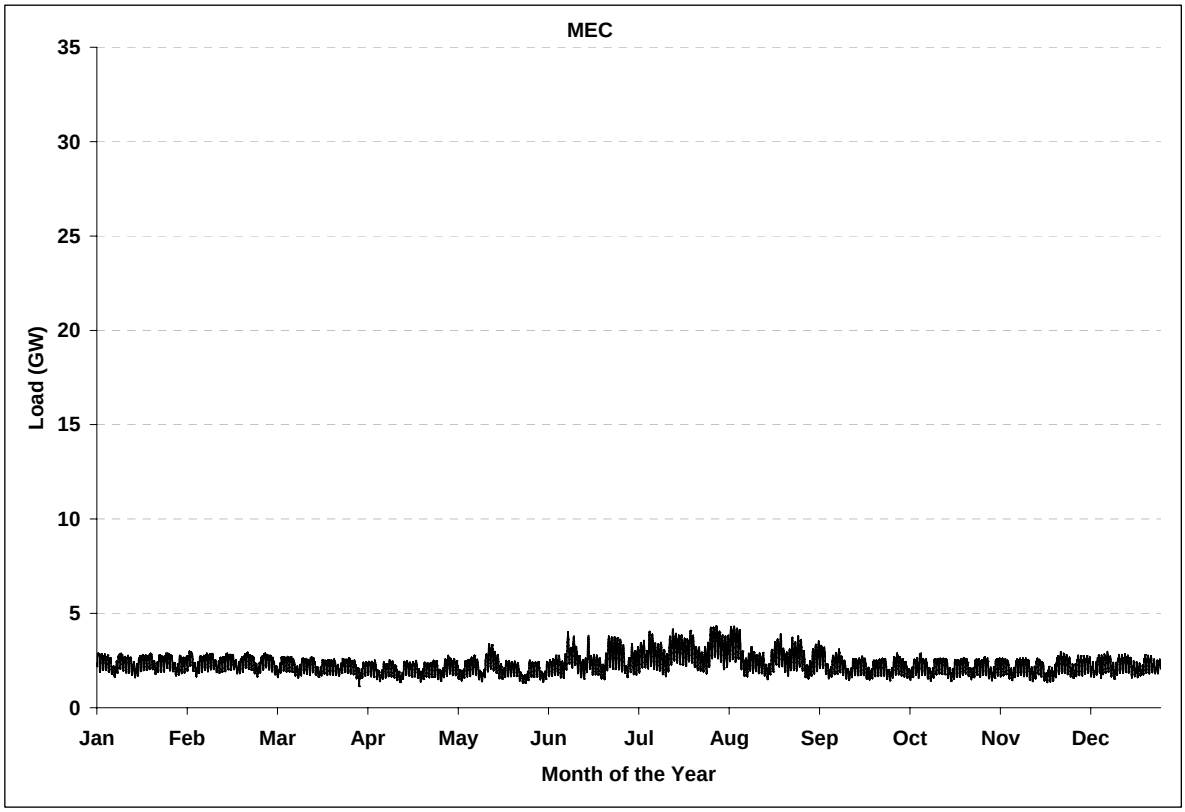

Figure D-28 MEC Load Curve

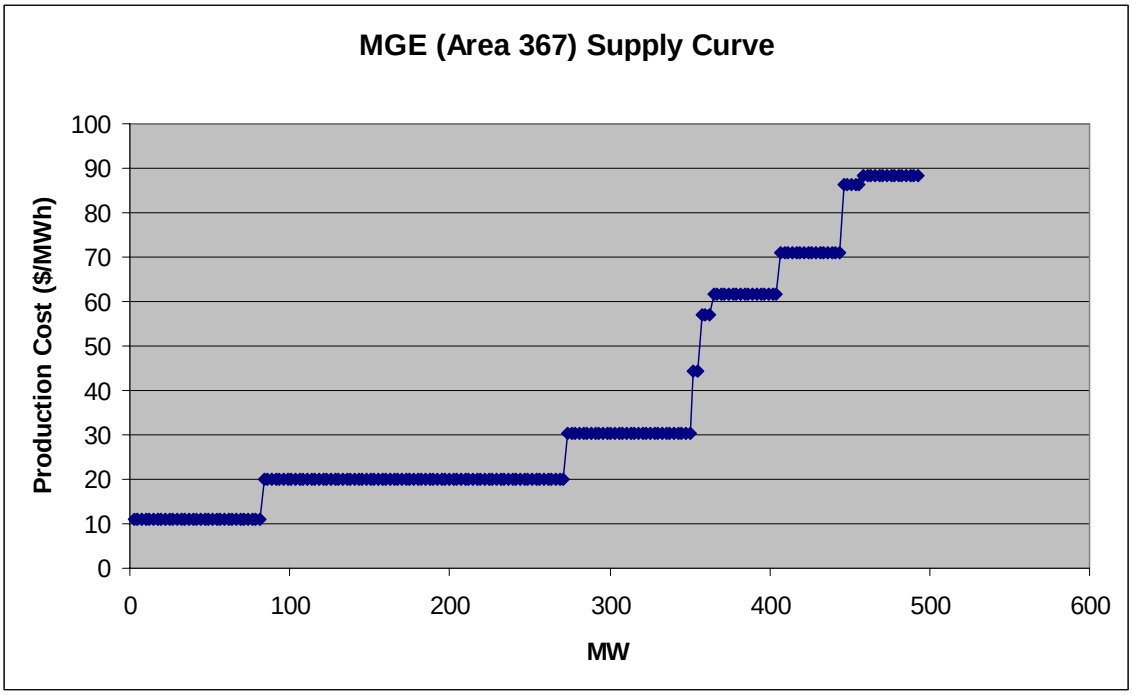

Figure D-29 MGE Generation Supply Curve

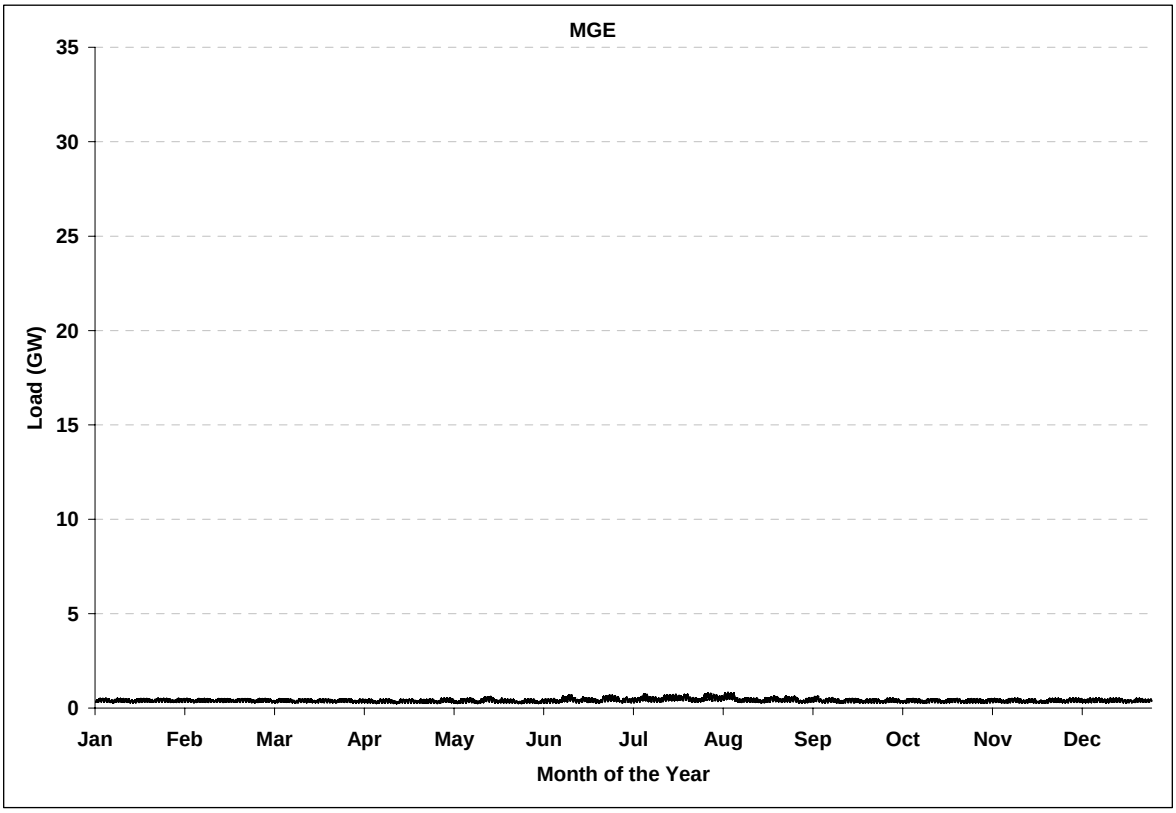

Figure D-30 MGE Load Curve

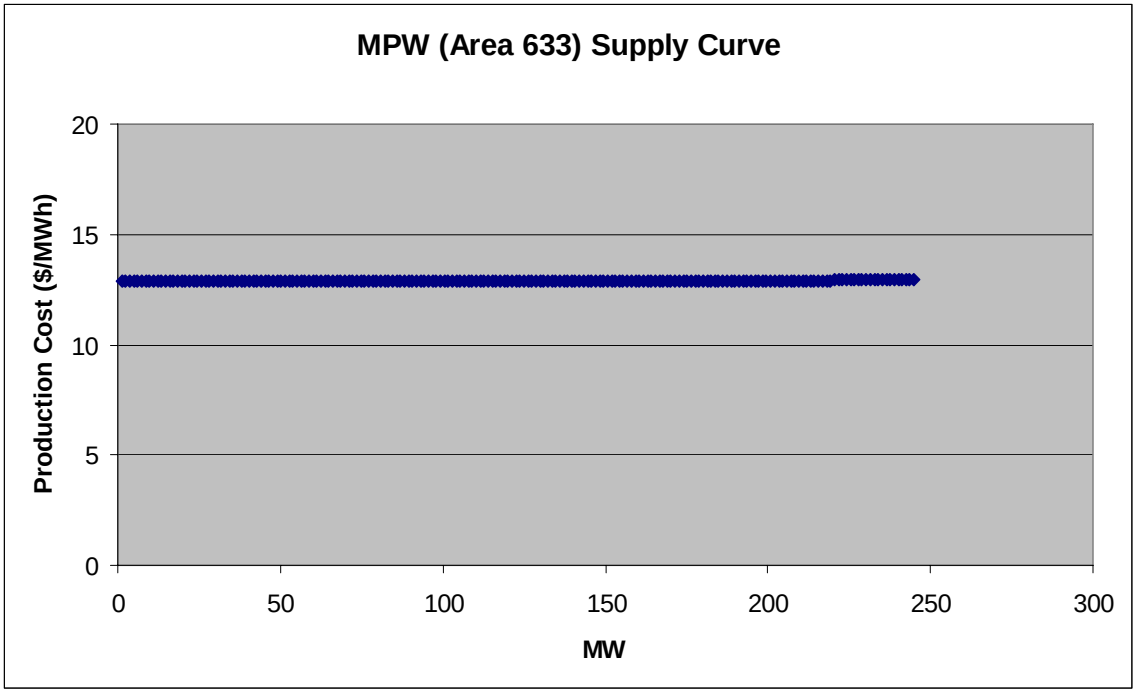

Figure D-31 MPW Generation Supply Curve

No loads projected in this area

Figure D-32 MPW Load Curve

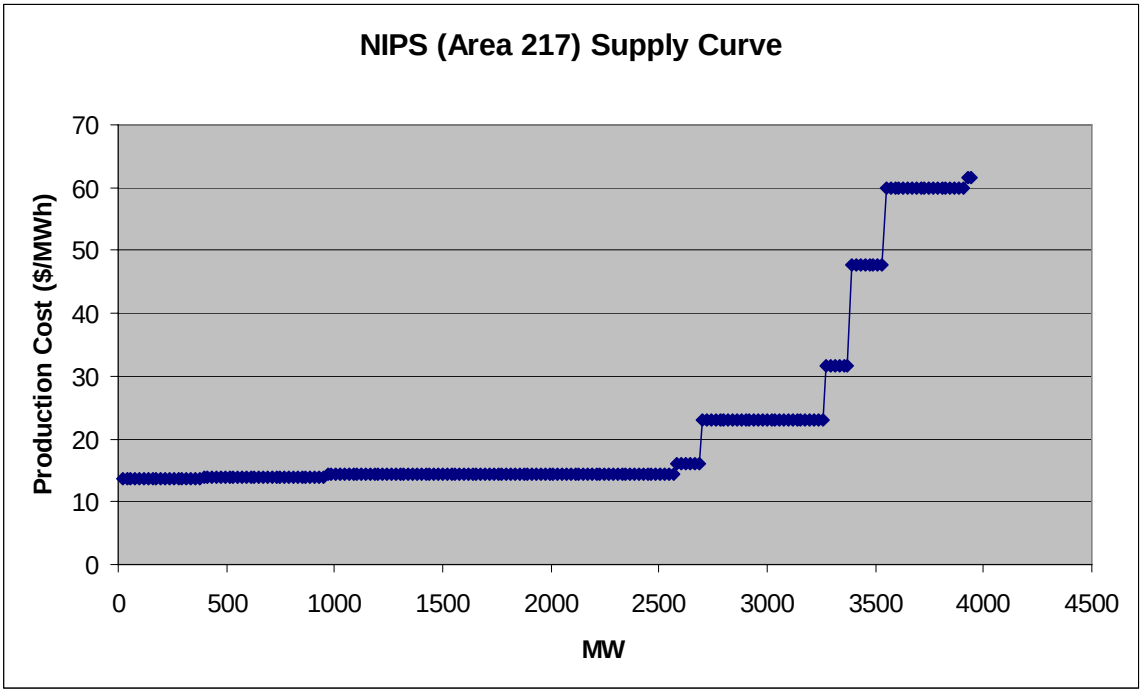

Figure D-33 NIPS Generation Supply Curve

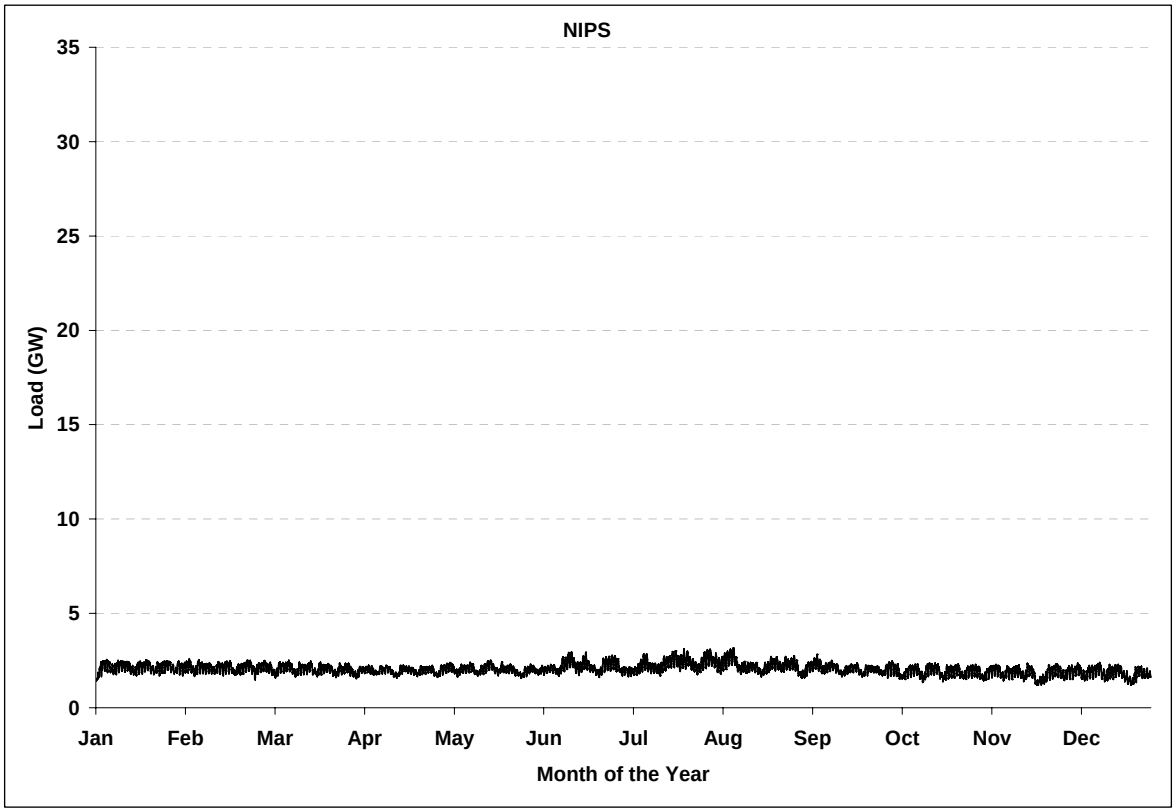

Figure D-34 NIPS Load Curve

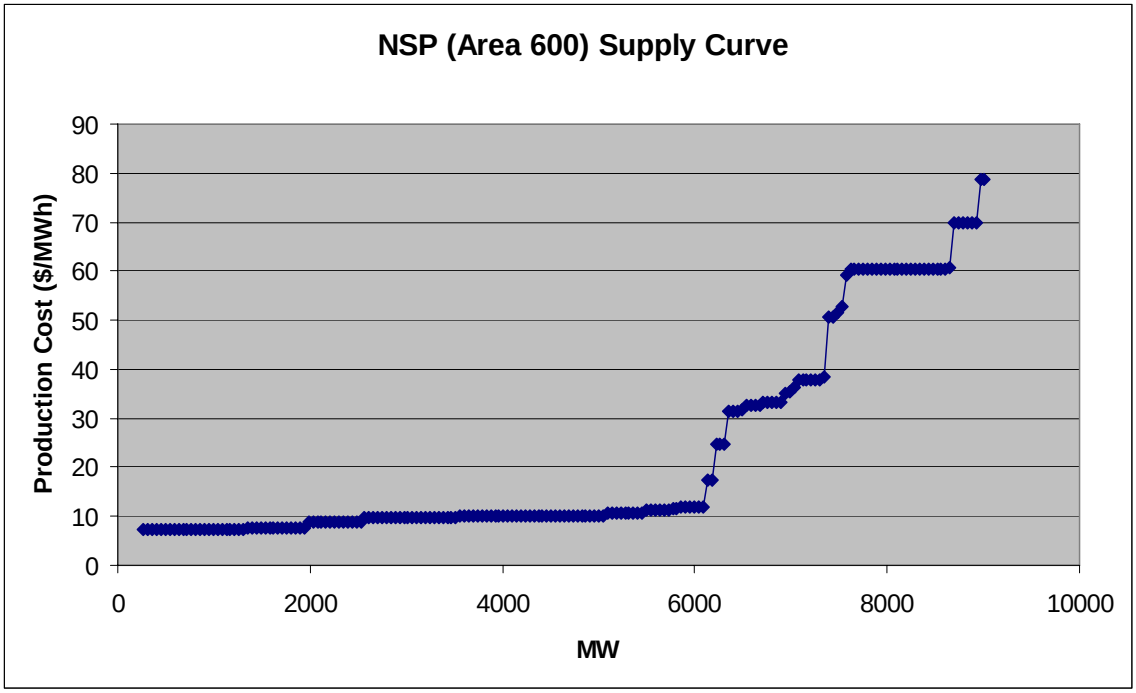

Figure D-35 NSP Generation Supply Curve

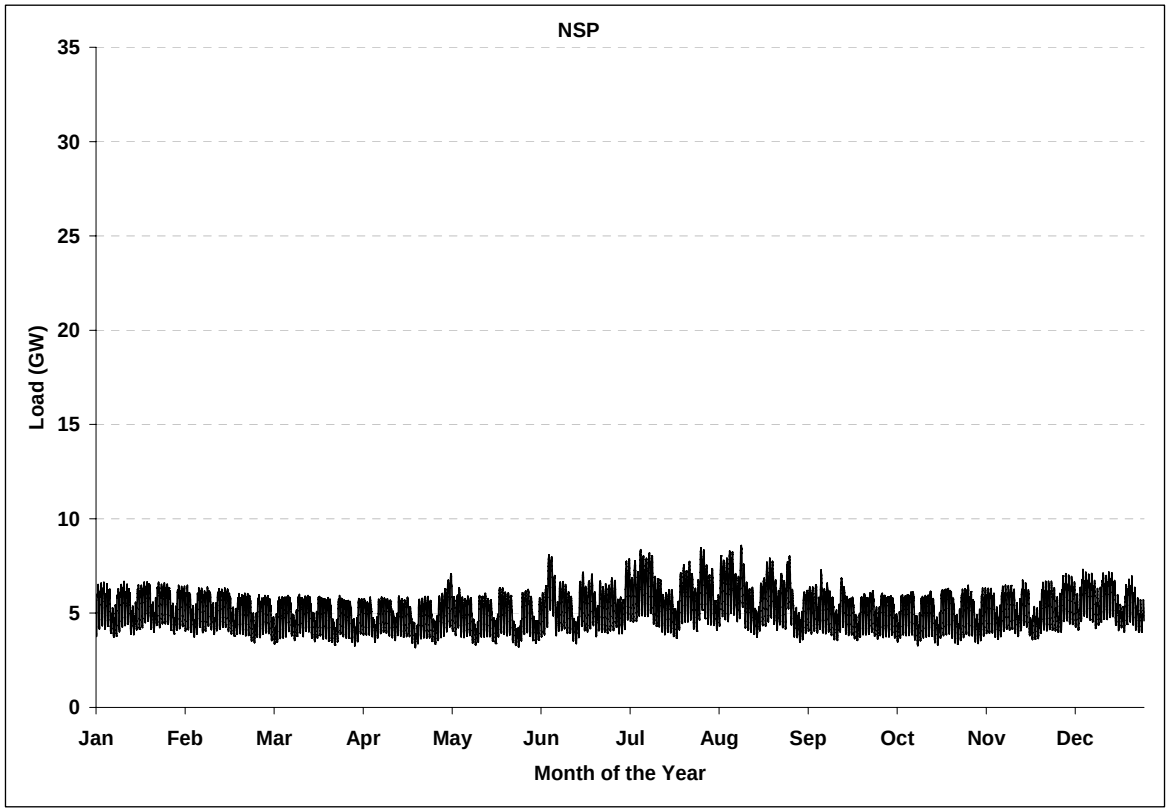

Figure D-36 NSP Load Curve

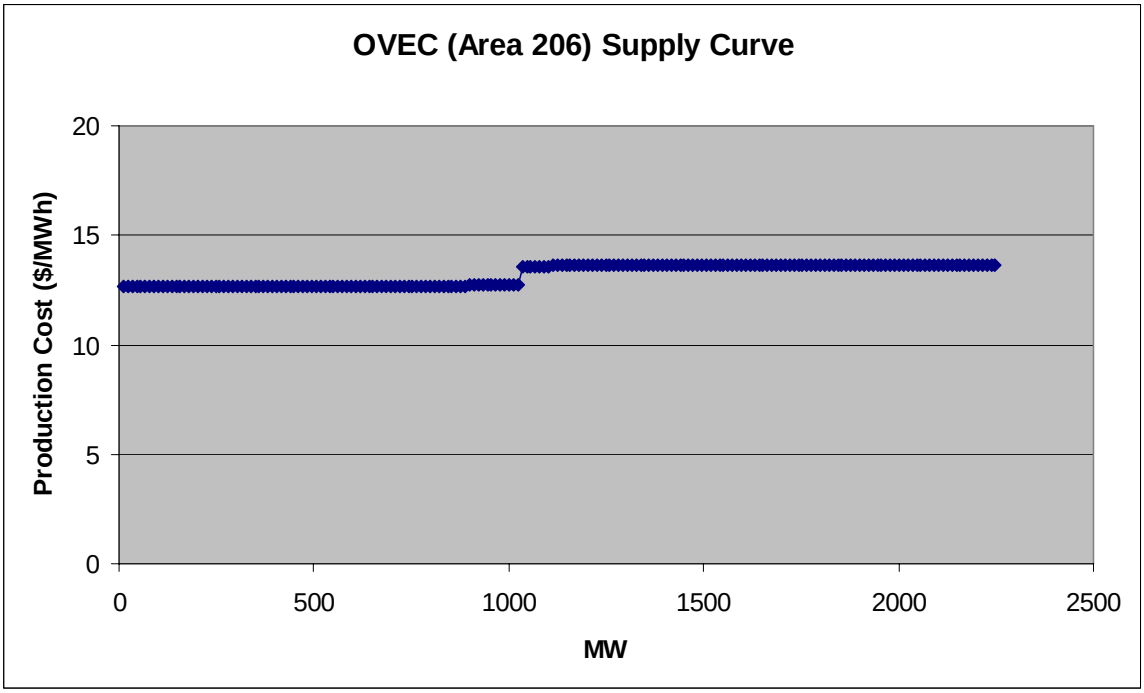

Figure D-37 OVEC Generation Supply Curve

No loads projected in this area

Figure D-38 OVEC Load Curve

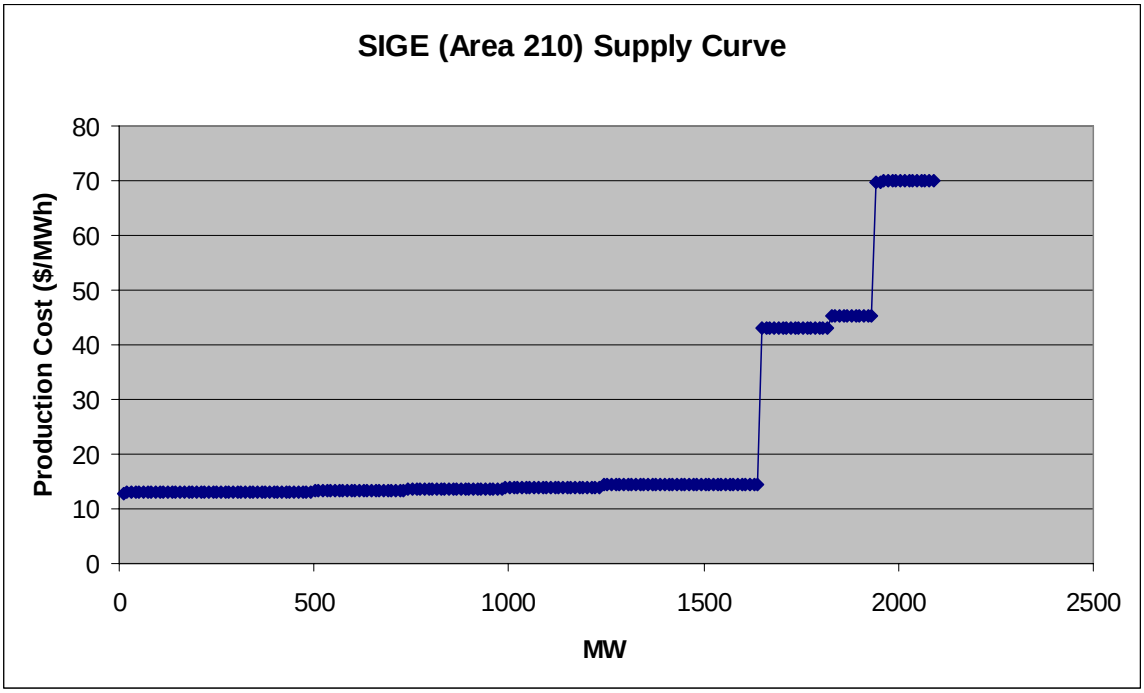

Figure D-39 SIGE Generation Supply Curve

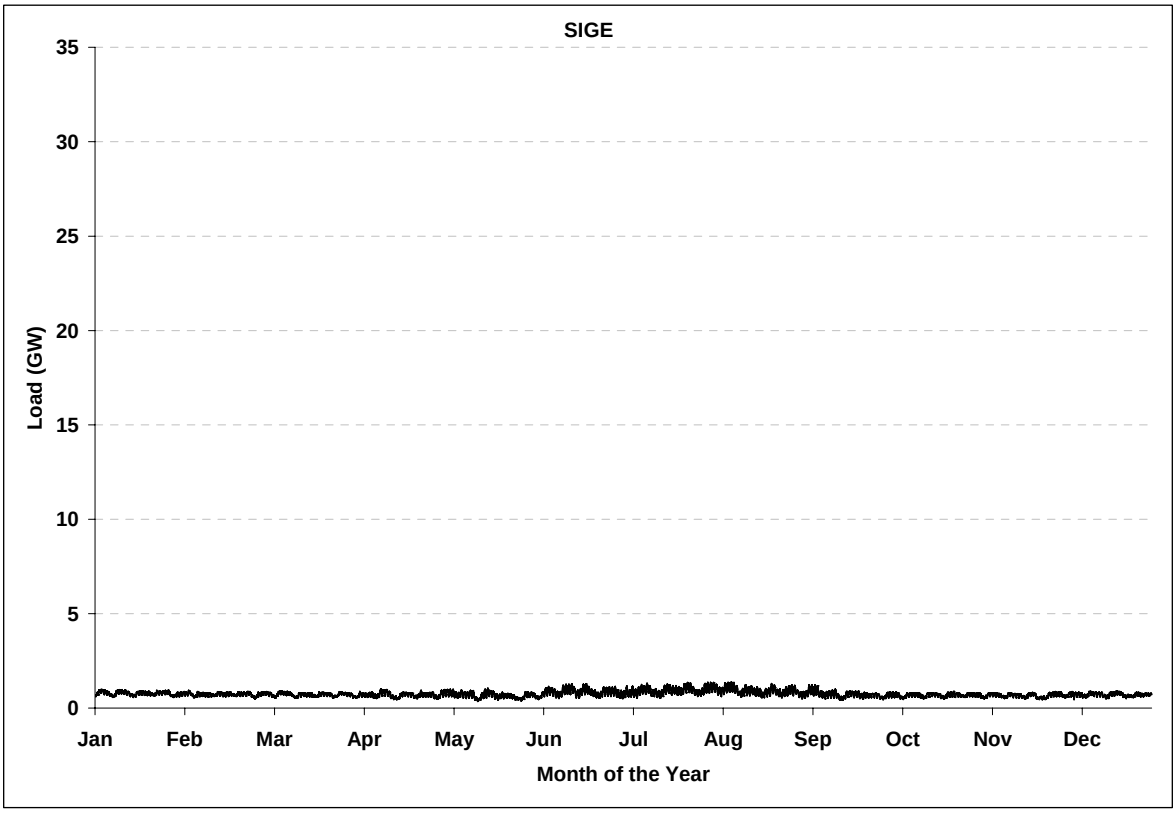

Figure D-40 SIGE Load Curve

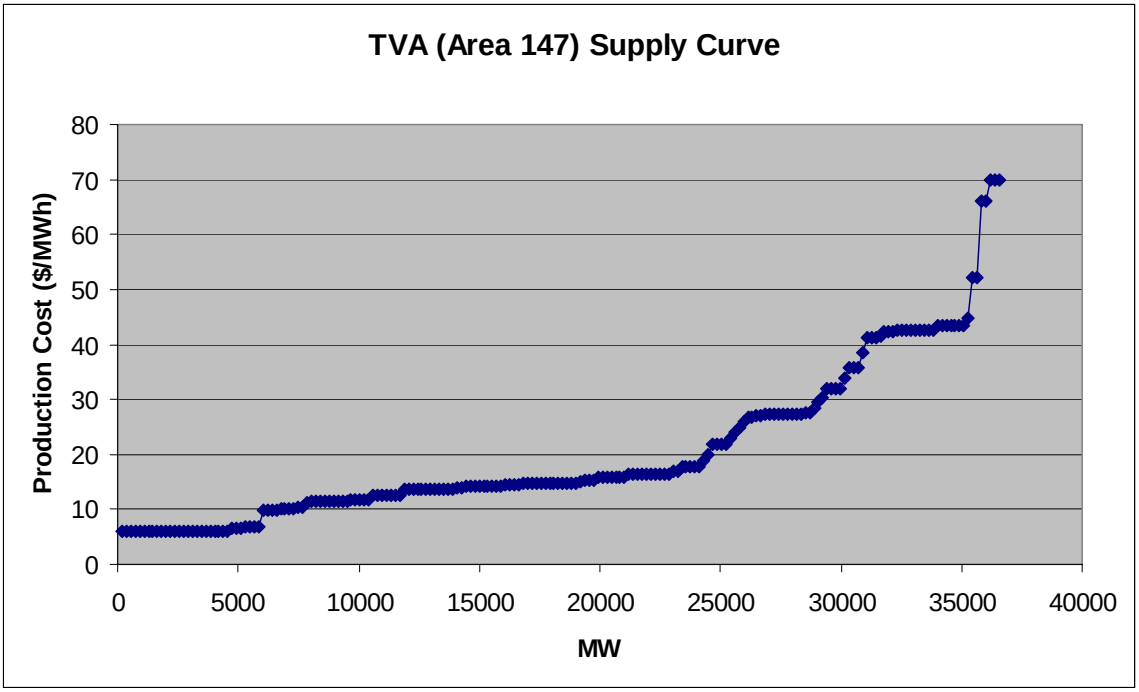

Figure D-41 TVA Generation Supply Curve

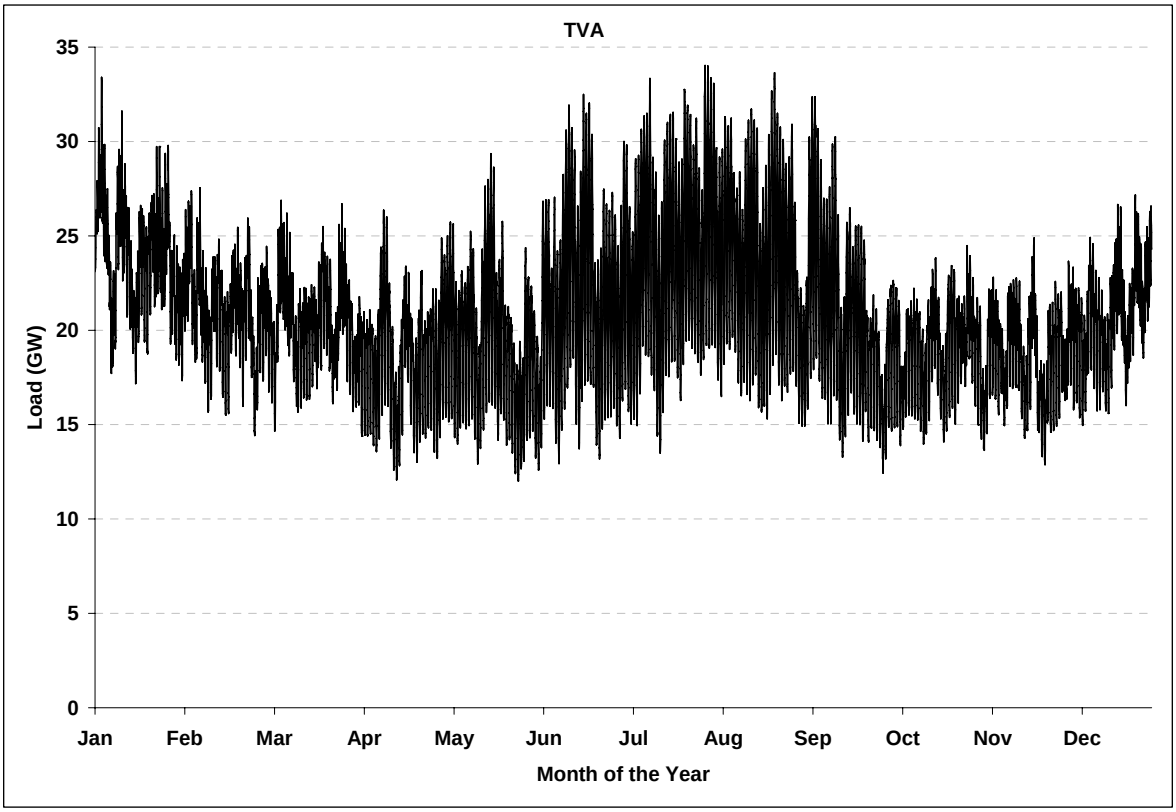

Figure D-42 TVA Load Curve

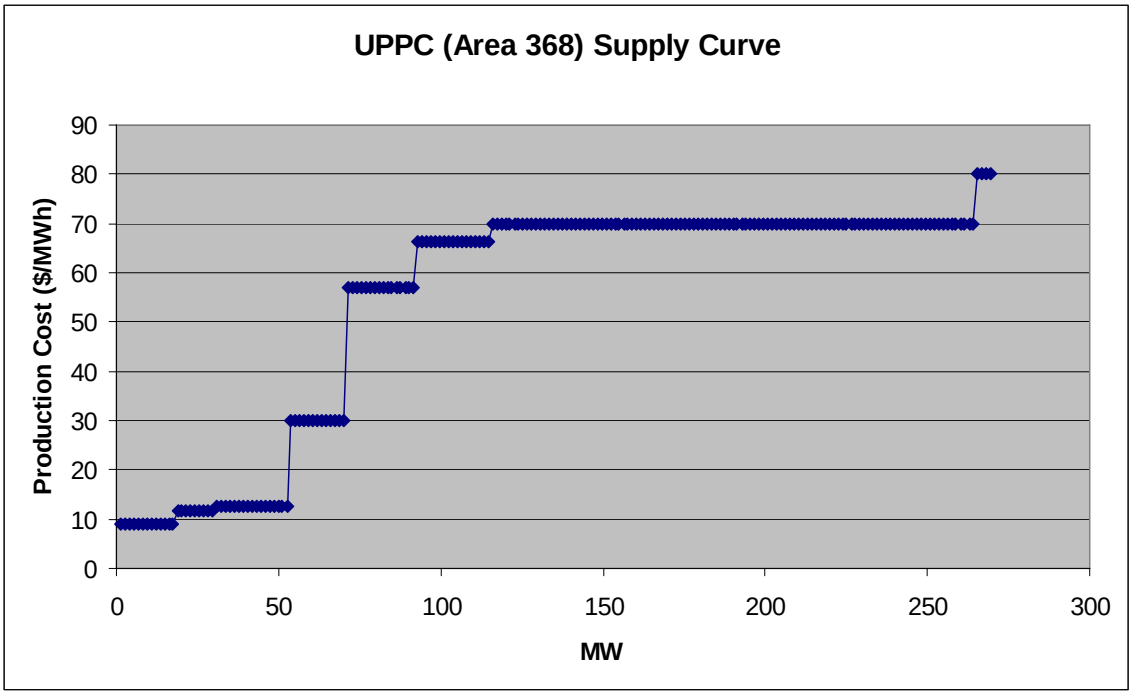

Figure D-43 UPPC Generation Supply Curve

No loads projected in this area

Figure D-44 UPPC Load Curve

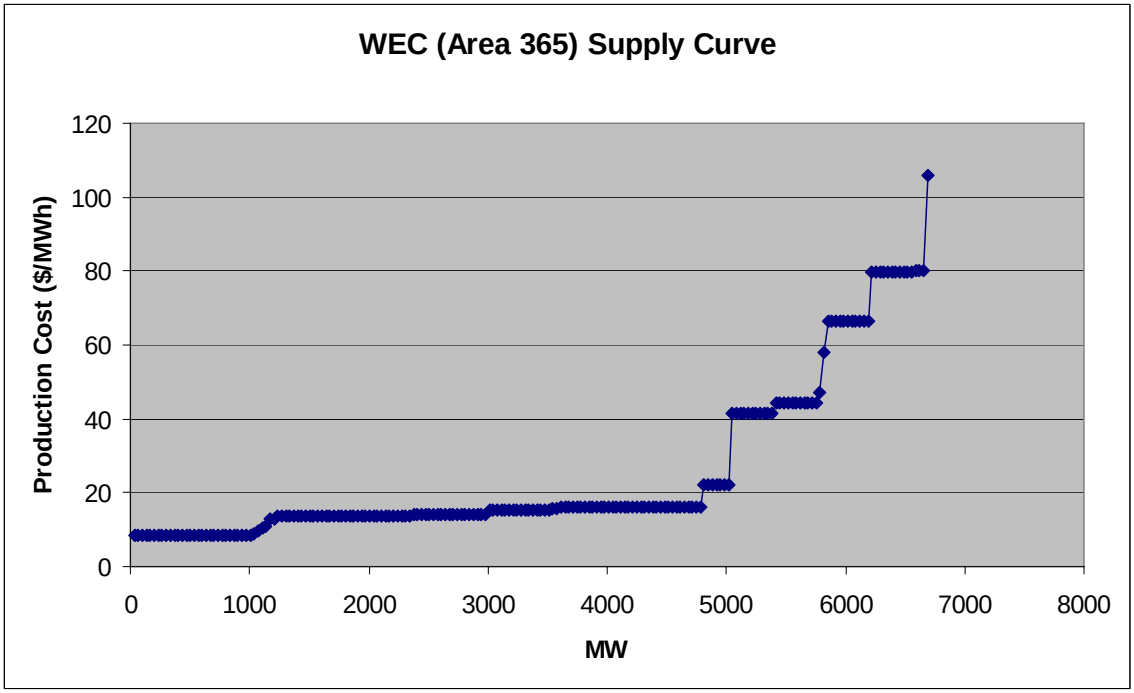

Figure D-45 WEC Generation Supply Curve

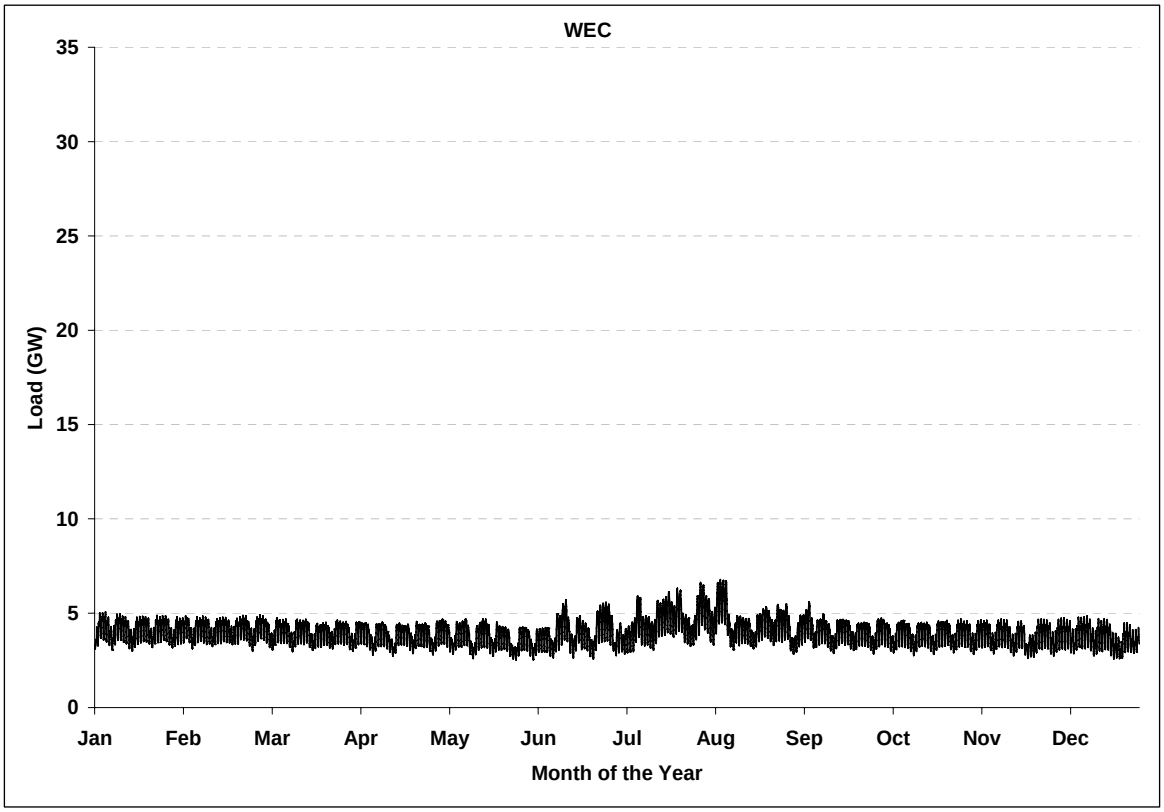

Figure D-46 WEC Load Curve

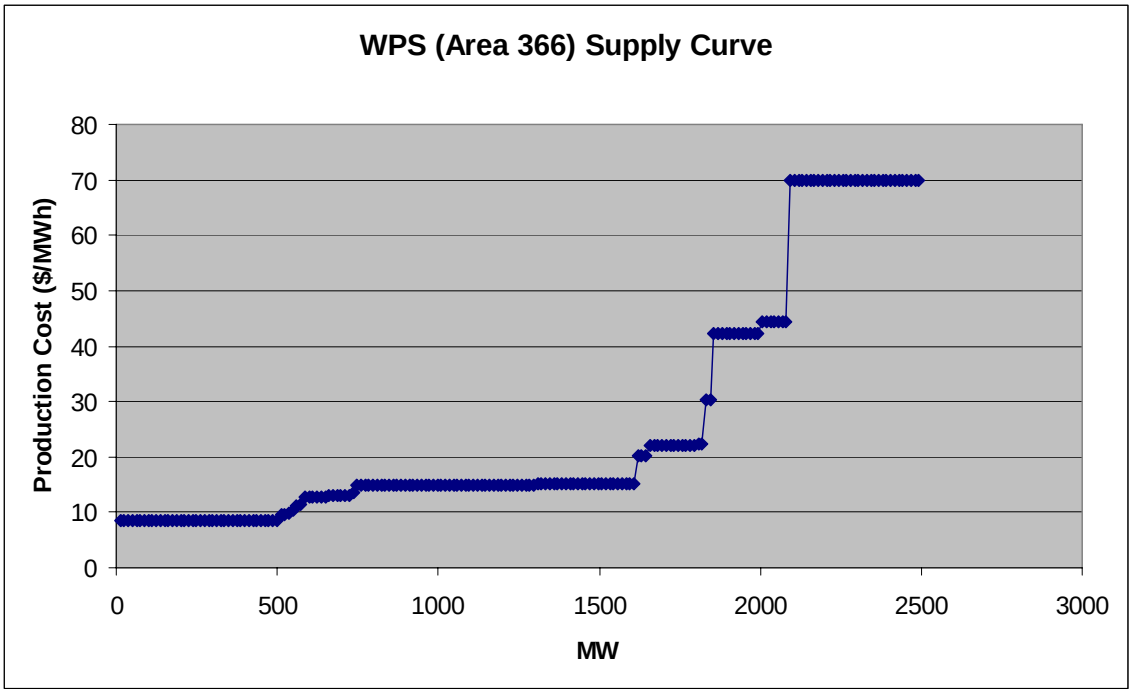

Figure D-47 WPS Generation Supply Curve

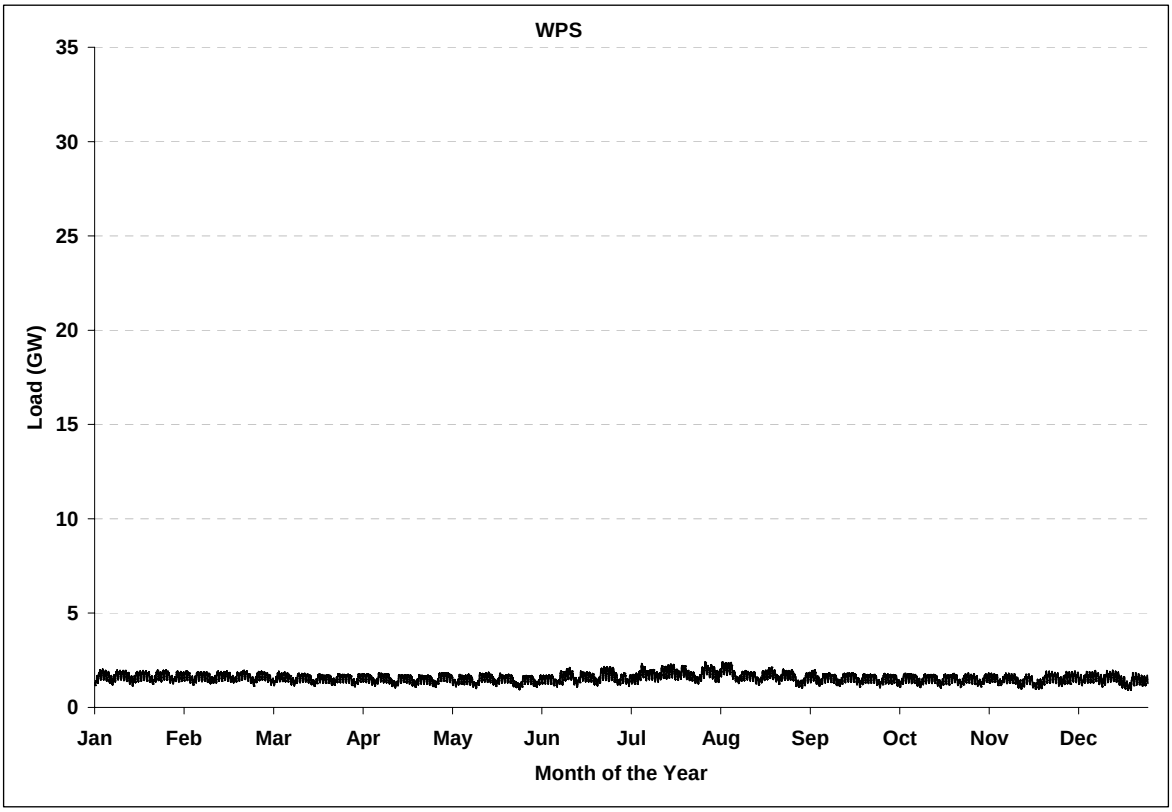

Figure D-48 WPS Load Curve

APPENDIX E
POWERWORLD® SUMMARY RESULTS

E.1 INTRODUCTION

E.1.1 PURPOSE OF THE STUDY

Despite the current adequacy of the generation and transmission system in Illinois, there is concern that the uncertainties of electricity restructuring warrant a more detailed analysis to determine if there might be pitfalls that have not been identified under current conditions. The problems experienced elsewhere in the country emphasizes the need for an evaluation of how Illinois might fare under a restructured electricity market.

The Illinois Commerce Commission (ICC) commissioned this study to be undertaken as a joint effort by the University of Illinois at Urbana-Champaign (UIUC) and Argonne National Laboratory to evaluate the Illinois situation in the 2007 period when restructuring is scheduled to be fully implemented in the State. The purpose of this study is to make an initial determination if the transmission system in Illinois and the surrounding region would be able to support a competitive electricity market, would allow for effective competition to keep prices in check, and would allow for new market participants to effectively compete for market share. The study seeks to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power in one or more portions of the State and thereby create undue pressure on the prices charged to customers and/or inhibit new market participants from entering the market. It should be noted that the intent of the study is not to predict whether or not such market power would be exercised by any company. Rather, it is designed to determine if a set of reasonably expected conditions could allow any company to do so.

It should also be emphasized that this study is not intended to be a comprehensive evaluation of the electric power system in the State. Rather, it is intended to identify some issues that may impact the effective functioning of a competitive market.

E.1.2 PURPOSE OF THIS APPENDIX

This purpose of this appendix is to provide supplemental information on the portion of this study performed by researchers at UIUC.

E.1.3 METHODOLOGY

The full study used two analytical tools in tandem: the Electricity Market Complex Adaptive Systems (EMCAS)©, developed by Argonne, and PowerWorld® Simulator. EMCAS is used to calculate the behavior of the agents participating in an electricity market. It focuses on the manner in which the market participants make decisions and on how they adapt their behavior to

market changes and to their own success or failure in the marketplace. PowerWorld is used to calculate the detailed operation of the physical power system. It provides a detailed look at generator dispatching, transmission loading, and contingency conditions for the various behavior patterns of the market participants. The use of both models provides the ability to look at the details of the market and the details of the physical power system in an integrated fashion. This appendix focuses on the results obtained at UIUC with PowerWorld using a model of the Midwest electricity system jointly developed by Argonne and UIUC.

E.1.3.1 PowerWorld Model

PowerWorld Simulator is an interactive power system simulation package designed to simulate high-voltage power system operation on a time frame ranging from several minutes to many days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses (i.e., transmission network connection points) using either a detailed ac power flow model or a less detailed but much faster dc power flow model. Powerful visualization techniques are used on an interactive basis, resulting in an intuitive and easy-to-use graphical user interface (GUI). The GUI includes animated one-line diagrams with support for panning, zooming, and conditional display of objects.

One of the add-ons available with Simulator is the security constrained optimal power flow (SCOPF). The advantage of having an SCOPF embedded into Simulator is that it is now possible to optimally dispatch the generation in an area or group of areas while *simultaneously* enforcing the transmission line and interface limits, both for the base case and for a set of contingencies. Simulator SCOPF can then calculate the marginal price to supply electricity to a bus (also known as the locational marginal price, or LMP), taking into account transmission system congestion. The advantage with Simulator is that these values are not just calculated; they can also be shown on a one-line diagram, on a contoured map, or exported to a spreadsheet. Simulator SCOPF was used to perform the power flow studies reported here.

E.1.3.2 UIUC Methodology

The overall methodology used in this study was to perform time-domain simulations (with a step size of one hour) of the anticipated 2007 Illinois region electricity market, using varying assumptions on the behavior of market participants. The UIUC portion of the study focused on doing the hourly SCOPF solutions using PowerWorld Simulator. Results from this portion of the study provide detailed information about the behavior of the power network, including power flow patterns, locations of congestion, and bus LMPs. In order to perform the simulations in a timely fashion, a dc power flow model was used for all the results presented in this report.

E.2 SCOPF MODEL

The key information needed for the hourly SCOPF analysis are: (1) the transmission network configuration including the electrical characteristics of the attached generators and loads, (2) the set of contingencies, (3) cost information for all the generators in the system, and (4) hourly changes to the system including variation in the load and the assumed on-line generators.

E.2.1 TRANSMISSION NETWORK CONFIGURATION (POWER FLOW MODEL)

The transmission network configuration was constructed from the 2003 summer peak power flow case prepared by the North American Electric Reliability Council (NERC) in November 2002, supplemented by slightly more up-to-date models provided by the Illinois utilities. The NERC model covered the entire North American Eastern Interconnect, a region stretching from the Atlantic to the Rockies (almost). Since the focus area of this study was the Midwest in general and Illinois in particular, this original 42,700-bus, 6,800-generator, 57,000-line/transformer NERC case modeled was equivalenced to reduce its size.

Determining the amount of detail to explicitly retain in an equivalent is a judgment call. Retaining more buses results in a potentially more accurate model (provided one has detailed cost information for the vast majority of the retained generators!) but the model takes longer to solve. Eliminating more buses results in improved solution times, but with a potential loss of accuracy. Given the study's focus on Illinois, all of the electric devices within Illinois were retained. Then, in order to provide a sufficiently large market for the Illinois generators and load yet one that was still manageable from a computational and data gathering viewpoint, the system was reduced to one covering the region roughly bounded by Minnesota, Missouri, Tennessee, Ohio, and Michigan.

Overall, the equivalent had 12,925 buses, 1,790 generators, and 17,647 lines and transformers. The total generation capacity was reduced from about 780 GW in the original NERC case to about 216 GW. While the reduced case had only about one-quarter the generation capacity of the original case, it still contained more than four times the total Illinois generation capacity (171 GW out-of-state and 45 GW in-state). Hence, the reduced case provided the desired "large" generation and load market. The breakdown of the 12,925 buses by NERC region was 2,207 in SERC, 4,052 in ECAR, 1,929 in MAPP, and 4,737 in MAIN (1,847 in-state and 2,890 out-of-state). During the study, the limits on all in-state transmission lines were enforced, but limits were only enforced for out-of-state lines with nominal voltage levels above 200 kV. This allowed direct consideration of the major transmission constraints on Illinois power imports/exports. Figure E.2-1 shows a one-line of the Illinois portion of this model, while Table E.2-1 shows a breakdown of the out-of-state generation and load.

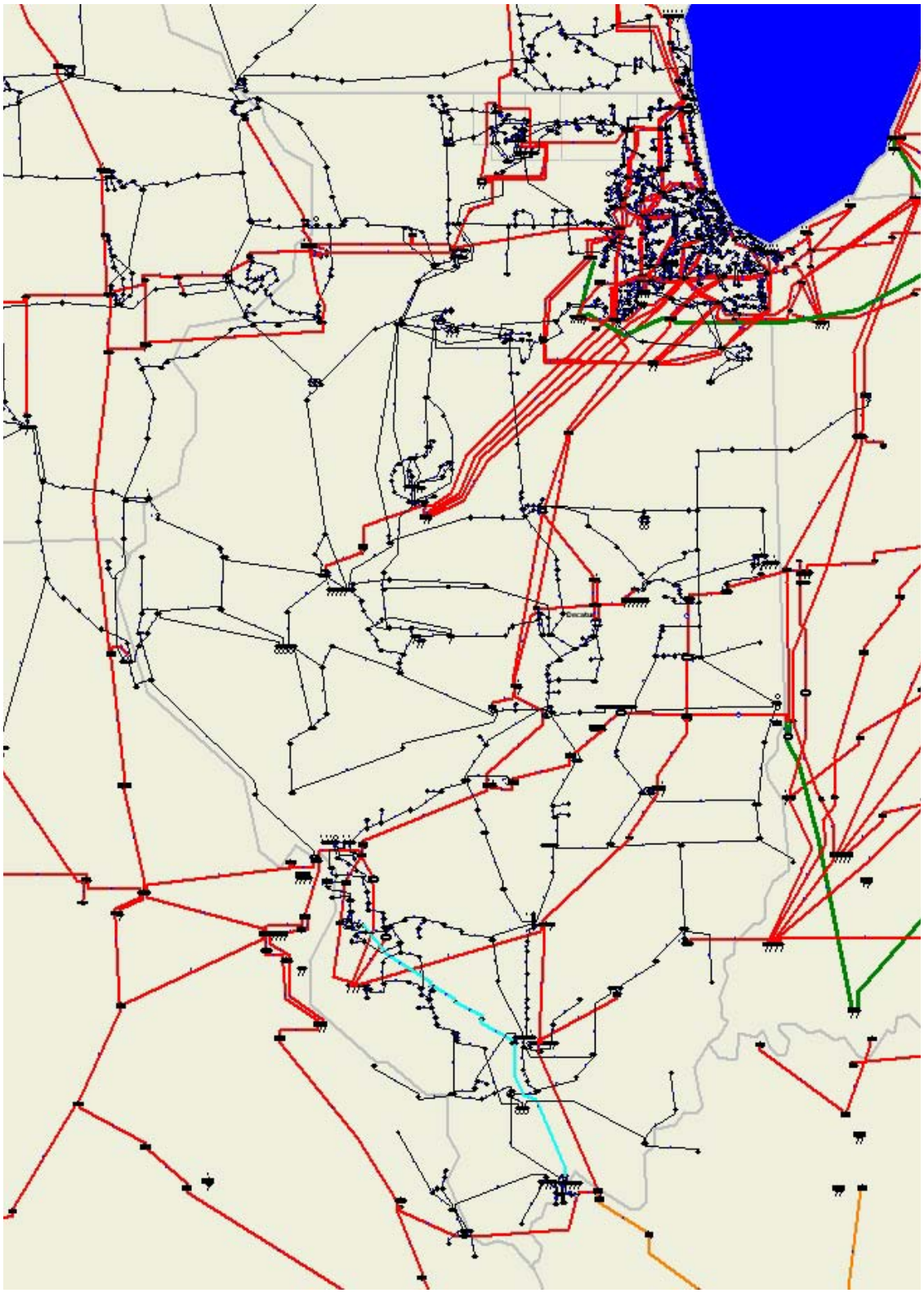

Figure E.2-1 Detailed PowerWorld Simulator One-line of Illinois Transmission, along with High Voltage Transmission in Other States

Table E.2-1 Out-of-State Generation and Load Modeled in PowerWorld Simulator

Control Area	Load (MW)	Generation Capacity by Fuel Type (MW)				
		Coal	Nuclear	Gas	Hydro/ Pumped	Other or Unknown
AECI (SERC)	4,415	2,412	0	1,614	58	249
TVA (SERC)	30,435	16,256	5,902	7,363	6,581	560
DOE (SERC0	500	0	0	0	0	0
AEP (ECAR)	23,094	21,300	2,060	6,455	731	292
OVEC (ECAR)	2,251	2,251	0	0	0	0
HE (ECAR)	1,250	1,250	0	240	0	50
CIN (ECAR)	11,775	10,171	0	1,831	75	1,220
DPL (ECAR)	3,437	3,305	0	1,410	0	0
SIGE (ECAR)	1,647	1,647	0	309	0	135
LGEE (ECAR)	7,314	5,928	0	796	71	1,259
BREC (ECAR)	1,558	1,709	0	0	0	65
IPL (ECAR)	2,971	2,664	0	742	0	100
NIPS (ECAR)	3,244	2,684	0	890	0	375
CONS (ECAR)	9,407	3,372	774	5,887	1,872	1,999
Other (ECAR)	0	0	0	1,776	0	0
ALTW (MAIN)	3,454	2,100	590	499	0	1,049
AMRN-NonIL	7,639	5,672	1,194	1,050	808	371
ALTE (MAIN)	2,505	2,034	0	1,136	26	264
WEC (MAIN)	6,792	3,640	1,012	1,032	143	868
WPS (MAIN)	2,486	1,019	500	432	131	414
Other (MAIN)	1,157	251	0	244	30	348
NSP (MAPP)	9,367	4,110	1,716	1,059	254	1,883
MEC (MAPP)	4,802	3,799	0	1,700	0	450
Other (MAPP)	939	1,257	0	84	21	60
Total	**142,439**	**98,831**	**13,748**	**36,549**	**10,801**	**12,011**

E.2.2 CONTINGENCIES

Secure power system operation requires that the system be operated both with no base case limit violations and also with no violations under a specified set of contingent conditions. Individual contingencies usually consist of the loss of one or more transmission lines/transformers or generators. When the operation of the power system is constrained due to transmission limitations, it is practically always constrained by contingent (as opposed to base case) violations. Hence, determining which contingencies to include in a study is vitally important. In this study, the impacts of 1,360 different contingencies were considered. While many of the contingencies consisted of single-line or transformer outages, others consisted of multiple-device outages (with the most complex contingency having 18 different actions). This set of 1,360 was developed using two sources. First, the in-state contingencies were developed from the list of contingencies provided by Illinois utilities. Second, the out-of-state contingencies consisted of single transmission line/transformer outages on key devices located electrically close to Illinois. Table E.2.2 shows a breakdown of the contingencies by company. During the study, contingent line flows were enforced using the power flow case “B” limit set (as indicated by the Illinois utilities). This was done using PowerWorld Simulator’s security constrained optimal power flow (SCOPF).

Table E.2-2 Contingencies by Company

Company	Number of Contingencies
Ameren	266
Central Illinois Light Company (CILCO)	38
Commonwealth Edison (ComEd)	450
ECAR (Total)	196
Electric Energy Inc. (EEI)	35
Illinois Power	120
MAIN (other)	129
MAPP (Total)	86
SERC (Total)	10
Southern Illinois Power Co-operative (SIPC)	12
Springfield City Water Light & Power (CWLP)	18

E.2.3 GENERATOR COST INFORMATION

The electrical characteristics for all the generators in the study were contained within the original NERC power flow case. These characteristics included the location of the generator on the grid and its minimum/maximum generation capacity. However, power flow cases do not include cost information for the generators, since this information tends to be viewed as more proprietary. But to perform this study, such cost information was crucial, with the necessary data including generator heat-rate, fuel type, variable O&M costs, and fixed-cost information. The initial model used here for the marginal generation costs was heat rate (MBtu/MWh) multiplied by fuel cost ($/Mbtu) plus variable O&M cost ($/MWh). For the in-state generation, all model information was provided by Argonne. For the out-of-state generation, this information was determined by UIUC using a variety of sources. The assumed fuel costs for both the in-state and out-of-state generators were provided by Argonne using DOE Energy Information Administration (EIA) data grouped by census region.

E.2.4 HOURLY SYSTEM VARIATIONS

The UIUC portion of the study consisted of doing hourly SCOPF simulations for year 2007 conditions. The hourly variation in the electric load was as provided by Argonne, with the same scaling values used for the in-state and out-of-state load. For the generator variation, all generators were assumed to be available at all times, unless they were explicitly outaged or derated. For the in-state generation, the studies were done using a generator outage schedule provided by Argonne. The purpose of this schedule was to model the planned and forced outages of individual generators that occur in actual system operation. For the out-of-state generation, the maximum real power capacities of the generators were derated to represent planned and forced outages; individual generator outages were not modeled for the out-of-state generators. The assumed derate values varied by month, representing the fact that most planned outages occur during the spring and fall when the electric loads are lower.

E.3 SCOPF RESULTS

In order to identify potential congestion regions for 2007, the full 12,925-bus, 1360-contingency model was solved using the PowerWorld SCOPF for all 8,760 hours in year 2007. The inputs to the model were essentially identical to those used in EMCAS, with the important exception that the SCOPF simulated a much larger network, and included the contingency constraints.

The hourly simulation approach, coupled with the scheduled and forced generator outages discussed in Section E.2.4, examined a wide variety of different system operating conditions. This wide variety of operating points caused a large number of constraints (i.e., contingency and line/transformer pairs) to become binding for different hours. This helped to identify the set of constraints that could be used by generators to exploit market power. However, such a detailed approach also generated a tremendous amount of data. For example, a full-year study creates over 100 million LMPs (i.e., LMPs at each of the 12,925 buses for every hour of the year) and over 50,000 binding constraint-hours. Effectively summarizing these results has been a significant challenge. This section (Appendix E) attempts to provide such a summary, with more detailed results contained in Appendix F.

E.3.1 RESULTS OVERVIEW

The initial 2007 run modeled a market in which all generators submitted bids equal to their actual production cost, that is (using the model from Section E.2.3), heat rate multiplied by fuel cost plus variable O&M cost. Table E.3.1 summaries the monthly results of this run, with the second column showing the monthly load, the third column showing the generation, the fourth showing the net exports for the month, and the last showing the average LMP (in $/MWh). Table E.3.2 shows a breakdown of the quarterly exports between Illinois and the rest of the model by direction, with the North direction, the net flow on the tie-lines with Wisconsin; East, the net flow on the tie-lines with Indiana (ECAR); South, the tie-lines with Kentucky (TVA); and West, the tie-lines with Iowa and Missouri.

Table E.3-1 Initial In-State Load, Generation, and Exports

Month	Load (GWh)	Gen. (GWh)	Exports (GWh)	Avg LMP $/MWh
January	13,588	13,541	–50	15.26
February	12,028	11,665	–365	14.57
March	12,442	12,202	–242	15.14
April	11,206	10,212	–995	15.14
May	12,062	11,406	–657	14.64
June	13,550	12,611	–941	16.21
July	15,740	15,310	–432	17.84
August	15,628	15,381	–247	18.30
September	12,155	11,586	–570	14.83
October	11,749	11,051	–699	14.95
November	11,233	10,620	–614	14.60
December	12,647	12,345	–304	14.20

Table E.3-2 Initial Exports by Quarter and Direction

Qtr.	Total (GWh)	North (GWh)	East (GWh)	South (GWh)	West (GWh)
1st	–657	1,331	–1,465	2,117	–2,640
2nd	–2,592	1,101	–2,229	1,978	–3,442
3rd	–1,249	1,992	–3,756	2,122	–1,607
4th	–1,617	1,406	–1,447	1,841	–3,417

The tables show Illinois as a net importer of electricity, a result contradicted by historical data for most recent years. However, it must be pointed out that the results are quite sensitive to the cost models used for both the in-state and the out-of-state generation. Small changes in the assumed generator cost characteristics can substantially alter the net Illinois interchange.

There appear to be several reasons for this interchange discrepancy. First, because of the scope of the study, detailed cost models were only developed for in-state generation. While significant time was spent determining the unit type and fuel type for the over 1400 out-of-state generators, the model parameters were not researched as extensively as for the in-state generators. In particular, the variable O&M costs are probably not as accurate, with the average values for the out-of-state coal units about $1/MWh less than those in-state. While this value may seem small, upping these variable O&M costs would substantially alter the interchange patterns. Second, the breakdown of the EIA fuel prices by census division resulted in the modeled prices of coal and natural gas for units immediately to the west of the Mississippi river (within the West North Central Census Division) to be substantially lower than the price in Illinois (within the East North Central Census Division). This is the primary reason for the heavy imports from the West shown in Table E.3-2, and for the low LMPs in Table E.3.3 for areas AMRN, NSP, MPW, MEC, and DPC. Third, while the 12,925 bus model contained a significant portion of the Midwest electric grid, it did not include PJM and areas further to the East, areas that tend to have higher costs than the Midwest and tend to be net importers from Illinois. Hence the impact of exports to these areas was not included in the study, somewhat skewing the results.

Table E.3-3 Initial Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
130	AECI	SERC	16.01	600
147	TVA	SERC	16.26	–4,165
148	DOE	SERC	14.52	–325
205	AEP	ECAR	15.68	2,162
206	OVEC	ECAR	15.57	1,776
207	HE	ECAR	15.52	306
208	CIN	ECAR	15.52	950
209	DPL	ECAR	15.63	415
210	SIGE	ECAR	15.30	414
211	LGEE	ECAR	15.56	708
214	BREC	ECAR	15.19	32
216	IPL	ECAR	15.37	203

Table E.3-3 Initial Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
217	NIPS	ECAR	15.59	–541
218	CONS	ECAR	15.70	–3,589
221	AEWC	ECAR	15.23	–1
222	AEWI	ECAR	15.28	–1
223	DEVI	ECAR	15.28	0
224	DEWO	ECAR	15.66	36
331	ALTW	MAIN	14.19	–424
355	CWLD	MAIN	14.70	–175
356	AMRN	MAIN	14.74	1,279
357	IP	MAIN	15.02	–162
359	CILC	MAIN	15.84	–414
360	CWLP	MAIN	15.23	–199
361	SIPC	MAIN	14.78	–144
362	EEI	MAIN	14.15	846
363	NI	MAIN	15.73	73
364	ALTE	MAIN	16.76	94
365	WEC	MAIN	16.44	–885
366	WPS	MAIN	17.29	–249
367	MGE	MAIN	16.30	–319
368	UPPC	MAIN	16.64	–51
600	NSP	MAPP	13.01	1,189
633	MPW	MAPP	14.65	49
635	MEC	MAPP	14.28	523
680	DPC	MAPP	13.71	–14

In order to assess the impact of this interchange skew on the results, a second year 2007 case was run with the generator costs altered to increase the cost of the external generation. This was done by adding an allocation of each generator's annual fixed costs to its bids, with the allocation done such that the costs of the out-of-state generators were increased slightly relative to the in-state generation (the net change was about $1/MWh). Results from this modified study are shown in Tables E.3-4 to E.3-6. More detailed results for both cases are presented in Appendix F.

A comparison of Tables E.3-1 to E.3-3 with E.3-4 to E.3-6 indicates that with the allocation of the fixed costs, Illinois has changed from being a net importer (with an average import of about 700 MW) to being a net exporter (with an average export of about 1,844 MW). This rather dramatic change is actually not unexpected, since in the second case the costs of the out-of-state generators have been increased relative to the in-state generation. A comparison of Tables E.3.2 and E.3.5 indicates most of this change is due to a dramatic increase in the Illinois exports to the east. The reason: the original cost differentials between the costs in the east and Illinois were small, partly due to both being in the same census region, and hence having the

same modeled fuel costs. Hence, even small changes in the relative costs could dramatically alter the interchange. Also, there are relatively few transmission limitations to the east.

Table E.3-4 Modified In-State Load, Generation, and Exports

Month	Load (GWh)	Gen. (GWh)	Exports (GWh)	Avg LMP $/MWh
January	13,588	15,264	1,675	17.79
February	12,028	13,575	1,547	17.23
March	12,442	13,935	1,493	17.65
April	11,206	11,713	507	17.56
May	12,062	13,511	1,449	17.28
June	13,550	14,704	1,154	18.82
July	15,740	16,878	1,138	20.54
August	15,628	16,976	1,348	21.03
September	12,155	13,825	1,670	17.53
October	11,749	12,609	860	17.39
November	11,233	12,370	1,137	17.14
December	12,647	14,825	2,178	16.84

Table E.3-5 Modified Exports by Quarter and Direction

Qtr.	Total (GWh)	North (GWh)	East (GWh)	South (GWh)	West (GWh)
1st	4,715	2,152	3,181	1,936	–2,554
2nd	3,110	2,228	2,176	1,979	–3,273
3rd	4,156	3,041	793	1,888	–1,566
4th	4,175	2,591	3,160	1,767	–3,343

Table E.3-6 Modified Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
130	AECI	SERC	18.01	562
147	TVA	SERC	18.44	–2,326
148	DOE	SERC	17.71	–321
205	AEP	ECAR	18.21	1,201
206	OVEC	ECAR	18.15	1,557
207	HE	ECAR	18.19	1,245
208	CIN	ECAR	18.16	462
209	DPL	ECAR	18.21	331
210	SIGE	ECAR	18.06	264
211	LGEE	ECAR	18.18	124
214	BREC	ECAR	18.07	-68
216	IPL	ECAR	18.05	154
217	NIPS	ECAR	18.20	–1,073
218	CONS	ECAR	18.25	–3,895
221	AEWC	ECAR	17.95	–1

Table E.3-6 Modified Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
222	AEWI	ECAR	17.98	–1
223	DEVI	ECAR	17.98	0
224	DEWO	ECAR	18.21	26
331	ALTW	MAIN	16.97	–466
355	CWLD	MAIN	17.31	–175
356	AMRN	MAIN	17.45	1,498
357	IP	MAIN	17.66	768
359	CILC	MAIN	18.42	101
360	CWLP	MAIN	17.74	–128
361	SIPC	MAIN	17.64	–141
362	EEI	MAIN	17.64	754
363	NI	MAIN	18.33	992
364	ALTE	MAIN	19.67	40
365	WEC	MAIN	19.17	–1,261
366	WPS	MAIN	20.03	–321
367	MGE	MAIN	19.26	–322
368	UPPC	MAIN	19.41	–51
600	NSP	MAPP	15.91	1,059
633	MPW	MAPP	17.46	57
635	MEC	MAPP	17.05	513
680	DPC	MAPP	16.60	–41

In contrast, the costs in the west were originally substantially lower than Illinois's, primarily due to a lower assumed cost for coal. Hence, a slight change in the assumed generator costs will have a lower impact. Also, transmission imports from the west are more constrained.

While the differences between the two cases may seem significant, the different assumptions on the generator costs actually had little impact on the focus of this study, that is, evaluating the impact transmission constraints would have on competitive electricity markets in Illinois. The reason is that, as previously stated, the hourly simulation approach placed the system in a wide variety of different operating conditions. Over the course of a day, the hourly interchanges would swing over a wide range, with power being imported for some hours and exported for others. This is illustrated in Figures F.1-1 to F.1-4 and F.2-1 to F.2-4 (in Appendix F), which plot the hourly Illinois interchange. While the average value is higher in the Appendix F.2 cases, the wide variation means that essentially the same constraints are binding in both cases, albeit perhaps for a different number of hours. The impact of transmission constraints on the Illinois electricity market is discussed in the next section.

E.3.2 ILLINOIS TRANSMISSION SYSTEM CONSTRAINTS

Constraints are the cause of LMP variation. Without constraints, all of the LMPs in the system would be identical, with their values set each time period by the cost of the single marginal generator. Power would flow freely from any generator in the system to any load. Of course, for a real power market, such a situation seldom, if ever, occurs. The operation of the grid is constrained by the need to avoid overloading any device under either base case conditions or during one of the contingencies. Therefore, to identify potential congestion regions, the impact of the individual constraints needs to be considered.

Tables F.1-1 and F.2-1 in Appendix F list the different binding device/contingency pairs in the two studies under consideration here, including both in-state and out-of-state constraints. As was mentioned earlier, devices practically always bind for contingencies, as opposed to base case conditions. For the first case (Appendix F.1 results), there were 240 different binding device/contingency pairs, with a total of 50,844 binding device-hours for the year, or an average of about 6 per hour. Table F.1-1 lists just the 104 device-contingency pairs that were binding for 25 or more hours for the year, along with the average and maximum marginal costs (in $/MWh) of enforcing these constraints. For the second case (Appendix F.2 results), there were 206 different binding device/contingency pairs, with a total of 38,605 binding device-hours for the year, or an average of about 4.4 per hour. Table F.2-1 lists just the 88 device-contingency pairs that were binding for 25 or more hours for the year.

However, in accessing the potential for congestion to segment the Illinois electricity market, it is actually better to focus on the variation in the bus LMPs rather than on the constraints themselves. As was mentioned earlier, the variation in the LMPs is caused by the constraints. But the determination of how a particular constraint affects the bus LMPs is actually rather complicated. One of the beauties of an LMP-based market is that end users do not (usually) need to worry about the details of how a particular LMP is determined. Rather, they can just respond to the result. The remainder of this section focuses on market segmentation caused by the constraints, with the individual constraints discussed only when necessary to understand the reason for the market segmentation.

Before moving on, it is important to briefly discuss one somewhat unique characteristic of the Illinois market – the presence of ten phase-shifting transformers in the ComEd control area. Usually, the flow of power through transmission lines and transformers can only be indirectly controlled by changing the real power outputs of the generator. Indeed, LMP price variations arise because at least some generation needs to be dispatched in a non-economic manner to avoid overloading the transmission systems. With few exceptions, the flow of power through a transmission line or transformer cannot be directly controlled. Phase-shifting transformers, however, are one of those exceptions (others include HVDC transmission lines, which are not present in Illinois). By controlling the phase angle of a phase-shifting transformer, the flow of power can be directly controlled. Such control is routinely done by ComEd to avoid overloading transmission lines in the City of Chicago. The impact of this phase-shifter control was included in the PowerWorld Simulator software used for this project, with the result being that there was very little congestion seen in the City of Chicago. If the impact of the phase

shifters had not been considered, one would have expected substantial congestion, with a pronounced increase in the LMPs in northeast Illinois (Lake and northern Cook Counties).

E.3.3 ILLINOIS TRANSMISSION SYSTEM CONGESTION REGIONS

This section details the regions of Illinois in which the LMPs are unusually high. The challenge in doing this assessment has been to make sense out of the many millions of LMPs generated by the computer runs done for this study. Figures F.1-5 to F.1-16 and F.2-5 to F.2-16 in Appendix F show the hourly variation (by month) of the average bus LMPs for the various utilities in Illinois. The figures indicate several general characteristics about the LMPs. First, the LMPs for all areas tend to increase during high-load periods (e.g., daytime during the summer) and decrease during times of low load. Because the generators are submitting bids equal to their marginal costs, the lowest LMP values tend to be fairly constant, with the value dictated by the costs for the base-load units. Second, for many hours, the changes in at least the average LMPs tend to be fairly uniform between the various utilities. That is, for many hours they have the same average LMP. However, the last characteristic is that there are some hours in which the average LMPs diverge quite significantly, particularly for Ameren-CILCO (CILCO), even under non-peak conditions. Also, periods of high prices in one area can result in low prices in another (e.g., March 2007, with several days of high prices in CILCO and low prices in CWLP). These deviations in the average prices are caused by transmission system constraints, which may be aggravated by planned or unplanned generator outages. However, while useful, just looking at the variation in the average LMPs across an entire control area can mask the effects of more localized congestion. To highlight the impacts of this congestion, we need to look at metrics derived from the individual bus LMPs.

There are a number of different metrics that could be used to highlight these regions of localized congestion. For example, Figures 17 to 28 in Appendix F show bus contour plots for each quarter in 2007 of the average LMP, the highest bus LMP, and the number of times the LMPs exceed a specified threshold (either $30/MWh or $40/MWh). The average LMP has the advantage of giving an overall feel for the price a consumer would pay at a particular bus, but has the disadvantage of masking significant variations in the price, particularly if a given bus's LMP is greater than average during times of high load and less than average during times of low load. Contouring the highest LMP for a time period (quarterly, in the figures) has the advantage of clearly showing the maximum price that occurred at each location. But the disadvantage is that information about the duration of the high prices is lost. Contouring the number of hours a given point is above a threshold combines some of the advantages of both, but at the expense of not showing the impact of very high but short-duration prices.

A complementary approach is to count the number of times a bus LMP is greater than the state-wide average by a specified percentage (10% here), and then to calculate the cumulative $/MWh by which it exceeds this threshold. The results of such a ranking are given in Tables F.1-2 and F.2-2 in Appendix F, with the top 100 buses with the highest cumulative $/MWh shown. For example, the first entry in Table F.1-2, bus 33002 (RS WALL) had an LMP greater than 110% of the hourly state-wide average for 298 hours (out of 8,640) with a cumulative $/MWh value of 11,739. This means on average its LMP exceeded 110% of the

average by 11,739/298 = $39.4/MWh. Figures E.3-1 and E.3-2 below show contours of this metric for all the buses in the State, with more detailed figures shown in Appendix F (Figures F.2-30 to F.2-33). A comparison of Tables F.1-2 and F.2-2, along with Figures E.3-1 and E.3-2, indicates that the regions of congestion in the State are fairly constant. For example, about 80% of the Table F.1-2 entries also appear in Table F.2-2, albeit with different values. The remainder of this section provides a detailed look at each one of these in-state congestion zones, along with a discussion of how congestion in the zone could be used by the generation companies to increase profits.

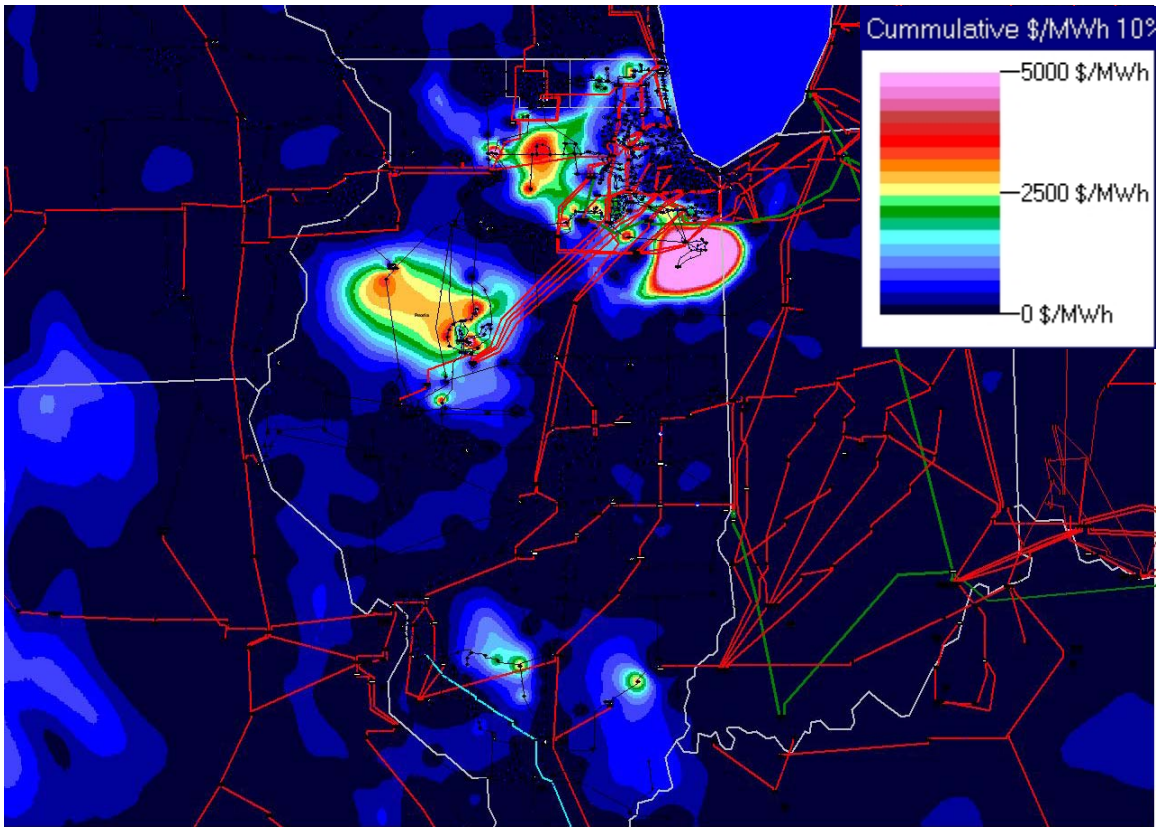

Figure E.3-1 Cumulative $/MWh 10% above Average for the Appendix F.1 Case

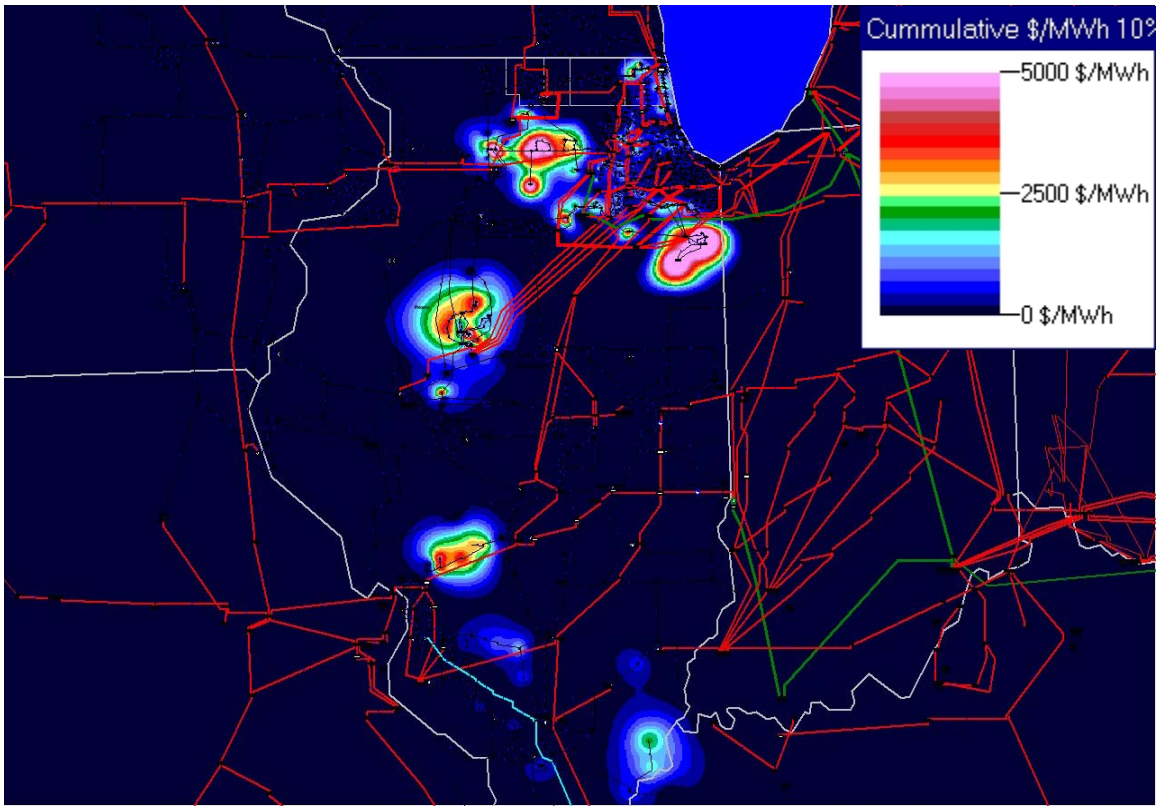

Figure E.3-2 Cumulative $/MWh 10% above Average for the Appendix F.2 Case

E.3.3.1 Peoria Congestion Region

The most significant congestion region occurred in the CILCO control area for both the Appendix F.1 and F.2 cases, with the values slightly higher in the latter. The presence of this congestion region is most evident in the control area average LMP plots for February, March, June, July, August, and November. The region also appears prominently in the highest LMP color contours for each quarter. As shown in Tables F.1-2 and F.2-2, the highest LMPs occur at the RS Wall and Edwards1 69-kV buses, followed closely by the Peoria and Pekin 138-kV buses. The complete extent of this region is shown visually in Figures F.1-31 and F.2-31.

These high LMPs are essentially due to SCOPF binding constraints on just two devices, the Holland-Mason 138-kV line (which is binding more than 80% of the time; these buses have high LMPs) and the RS Wall 138/69-kV transformer #1. The Holland-Mason 138-kV line binds for flow north from Holland to Mason (and on to Tazewell) for either the CIL-6 contingency (loss of Duck Creek-Tazewell 345 kV) or the ComEd 345-L0304_R-S contingency (loss of Tazewell-Powerton 345 kV). The RS Wall 138/69-kV transformer is binding for base case problems (due to it having a 90 MVA base case and 150 MVA contingency limit) with the flow always from the 138-kV to 69-kV buses.

The presence of above average LMPs at these buses also has good correlation with generator outages in the area. For example, for the Appendix F.1 case of the 298 hours during which the RS Wall 69-kV bus has high LMPs, 220 hours are associated with an outage of the Edwards #2 generator, 114 hours are associated with an outage of Edwards #3, 175 hours are associated with an outage of the Dresden #2 generator, and 157 hours with Quad City #2. In additional, several other ComEd generators have associates of more than 80 hours. Clearly, a localized congestion region is possible during times of generator outages either at Edwards or at electrically close ComEd generators.

The degree to which generators in the CILCO area could take advantage of this congestion to profitably increase the bus LMPs depends, of course, upon the particular system conditions, such as the load level, and which generators and/or lines are out of service. To provide more generic results, a case with load equal to 90% of system peak and no generator outages was studied using the Appendix F.2 cost characteristics. The system load should be at or above 90% of peak for about 80 hours per year.

The main generator within the congestion region is Edwards, a relatively low-cost coal plant with a total capacity of about 600 MW. To assess the ability of Edwards to profitably manipulate prices, its bids were scaled from initially being equal to its actual marginal cost (as was assumed in the Appendix F.1 and F.2 cases), to being equal to a scalar multiplier by its marginal cost. The results are shown in Table E.3-7, with the second column showing the total CILCO generation, the third column showing the relative profit (with unity corresponding to a marginal cost bid), while the last two columns show the average and maximum LMP for the CILCO area. Small increases in the Edwards bids have no impact on prices, since Edwards is initially dispatched at full capacity with bus LMPs above its marginal costs. When the bid scaling is 2.0, the share of the Edwards generation drops off, decreasing profit slightly. Then for higher bids, a situation is reached in which some Edwards generation needs to run, regardless of price. Once this point is reached, additional increases in the Edwards bids result in increased profits. For example, when the bid multiplier is 4.0, the total CILCO profits are 1.32 the initial profits. The minimum Edwards generation for the assumed 90% system load is 170 MW, with the binding constraint being the Holland-Mason 138-kV line. Hence we could conclude that under heavy system loading, even with all generators in-service, the Edwards generator has localized market power.

Table E.3-7 Variation in CILCO Profit Modified Edwards Bids (Base Case)

Edwards Bid Multiplier	Total CILCO Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	1,106	1.000	27.25	27.57
1.5	1,106	1.000	27.26	27.57
2.0	777	0.952	31.23	39.67
2.5	583	0.964	37.44	58.52
3.0	579	1.136	44.42	70.24
3.5	578	1.226	50.86	76.97
4.0	578	1.320	56.46	83.22

However, this binding constraint is currently in the process of being upgraded, with the changes affecting the entire Tazwell-Holland-Mason-East Springfield 138-kV line. The study results reported here were done using the original limits. Also, during the process of doing this analysis, it was noticed that the 138-kV ties between CILCO and IP at Richland (north side of CILCO) were modeled as being normally open in the base case. Subsequent checking indicates that these two lines should be modeled as closed. If these two changes are considered (with the most significant being the line upgrade), the Table E.3-7 results change substantially, with the new values given in Table E.3-8. The Edwards generator still has market power, but with its required generation decreased from 170 MW to 120 MW, requiring that its bid be about 6 times marginal cost for an increased profit. The binding constraint is now the Tazwell-East Peoria 138-kV line.

Table E.3-8 Variation in CILCO Profit Modified Edwards Bids with Upgraded Tazwell to East Springfield 138 kV Line

Edwards Bid Multiplier	Total CILCO Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	1,106	1.000	27.20	27.56
1.5	1,106	1.000	27.20	27.56
2.0	529	0.538	31.90	38.01
2.5	527	0.609	36.64	55.02
3.0	524	0.642	42.32	72.13
3.5	529	0.683	41.00	72.75
4.0	529	0.780	41.30	85.30
5.0	532	0.918	43.94	110.38
6.0	532	1.094	47.75	135.47

E.3.3.2 Kankakee Area Congestion Region

The second most significant congestion region occurs in the Kankakee area (ComEd operating area), with the most significant buses in the pocket listed in the second to twelfth entries in Table F.1-2, as well as the Wilmington 138 kV bus, and to a lesser extent the red Dresden 138-kV bus. This congestion region also is shown visually in Figures E.3-1, E.3-2, and in the bottom right of Figures F.1-32 and F.2-32. These high LMPs are due to an SCOPF binding constraint on the blue Davis Creek 345/138-kV transformer for the ComEd 345-L17704_R-S contingency (loss of the red Davis Creek transformer and several other devices). These high LMPs mostly occur on high-load days. The total peak load in this region is between 300 and 400 MW.

The higher marginal costs in the Kankakee area arise from needing to do a constrained dispatch to avoid the contingent overload of the 345/138-kV transformer at Davis Creek. For the 90% of peak case mentioned earlier, this constrained dispatch involves using the University Park natural gas turbine generators owned by Constellation Power. University Park has a total of six 50-MW turbines. For this case, the highest LMP in the Kankakee region is $54.18/MWh. Since the University Park generators are “marginal units,” changes to their bids will directly affect the bus LMPs, with the potential that such changes could increase Constellation’s total Illinois profit. The results of this analysis, which are shown in Table E.3-9, indicate that increases in the bids for the University Park generators could indeed increase Constellation’s profit, with the

tradeoff again between lower market share and higher prices. If the bids were increased to the profit maximizing value of 1.7 times marginal cost (assumed here to be $35.26/MWh), the highest LMP in the Kankakee region almost triples to $147.66/MWh.

Table E.3-9 Variation in Constellation Power Profit for Modified University Park Bids

University Park Bid Multiplier	Total University Park Gen. (MW)	University Park LMP	Relative Profit
1.0	104	35.26	1.000
1.1	103	38.79	1.128
1.2	45	42.31	1.193
1.3	42	45.83	1.171
1.4	42	49.35	1.204
1.5	33	52.89	1.192
1.6	29	56.42	1.201
1.7	29	59.94	1.232
1.8	0	63.22	1.008

E.3.3.3 Dixon Area Congestion Region

The next most significant congestion region appears in the vicinity of the ComEd Dixon 138-kV bus extending to the east to include Mendota and Steward. This congestion region is shown visually in the upper center of Figures E.3-1 and E.3-2, and in more detail in the left center of Figures F.1-32 and F.2-32 in Appendix F. The high prices at these buses are often caused by a binding constraint on one of the 138-kV lines going from Nelson to Dixon. These lines bind for the ComEd 138-L15507_B-R contingency (loss of the blue Nelson to Dixon 138-kV line) and the 138-L15508_B-R contingency (loss of the Nelson red 138 kV bus) (essentially the loss of the parallel line). These high LMPs mostly occur on high-load days, particularly with generator outages in the Rockford area.

There are no generators in the direct area of the constraint, so exploiting this constraint to maximize generation profit seems unlikely unless there is an outage of a large generator, such as one of the Byron units. Then the NRG units at Rockford may be able to increase their profit by submitting bids above marginal cost. For example, in the 90% of peak case with one of the Byron units outaged (and all other units in-service), if the NRG Rockford units bid 20% above marginal cost, their dispatch falls from 421 to 147 MW, but their profit increases by about 13%. Bidding 40% above marginal cost results in a 0 MW dispatch.

E.3.3.4 Mazon Area Congestion Region

The next congestion region appears in the vicinity of the ComEd Mazon 138-kV bus, extending towards the J-375, J-371, and J-339 buses. This congestion region is best seen visually on Figures F.1-32 and F.2-32 in Appendix F, to the southeast of the Dixon area. The high prices here are practically always caused by a binding constraint on the Oglesby-Mazon 138-kV line, with the binding constraint flow always going from Oglesby to Mazon. This constraint is usually caused by the ComEd 345-L15502_B-R contingency (loss of the Nelson-Electric Junction 345-kV line), with a significant minority caused by the ComEd 345-L2101-S

contingency (loss of a Brokaw 345-kV bus – also IP contingency IP108). The LMPs at Mazon are more than 10% above the state-wide average for more than 700 hours in the year, although usually they are not significantly above the average. A wide variety of generators are capable of helping to mitigate this constrain, so it is unlikely to be exploited for profit maximization.

E.3.3.5 Lombard Congestion Region

The next most severe congestion region appears for just 25 hours at the blue Lombard 138-kV bus and several surrounding blue buses (e.g., Glen Ellyn, Glendale, Nordic, Butte, Addison). The high LMPs are always caused by a binding constraint on the blue Lombard 345/138-kV transformer due to ComEd contingency 345-L12001_B-N (loss of the blue Itasca 345/138-kV transformer and the blue Lombard-Itasca 345-kV line). This constraint is only binding at the times of highest loading.

The most sensitive generators for controlling the flow on the constrained transformer, and hence with the best potential for inducing or enhancing the congestion, are all owned by Midwest Generation. The generating plants are Will County Unit 4, Joliet Unit 9, Crawford 7 and 8, Fisk 9, and Waukegan 6 and 8. Analysis of the 90% load case indicates that no single generator, or group of two or three generators, can benefit from this congestion (however, see Section E.3.4.2 for a discussion of a more company-wide strategy for Midwest Generation).

E.3.3.6 Galesburg Congestion Region

The LMPs at the Galesburg 138-kV bus and several surrounding buses are more than 10% above the state-wide average for about 1,700 hours in the Appendix F.1 case; they are much less problematic in the Appendix F.2 case. This congestion zone is shown visually in Figure E.3-1 and Figures F.1-30 and F.1-31. These high prices are caused by a binding constraint on the Galesburg 161/138-kV transformers (there are two, each with a rating of 100 MVA), with the flow direction always from the 161-kV to the 138-kV. Most of the time, these transformers are binding for ComEd contingency 345-L15502_B-R (loss of the Nelson-Electric Junction 345-kV line), but they are sometimes binding for contingency L0304-A (loss of the Tazewell-Powerton 345-kV line and the Tazewell-Mason 138-kV line), or contingency 345-L0404_R (loss of the Quad City-H471 [NW Steel] 345-kV line). This constraint occurs when there are high imports from Iowa. Since there is little generation in the immediate vicinity of the constrained buses, it is unlikely that this constraint could be exploited for profit maximization.

E.3.3.7 Wilson/Round Lake/Antioch Congestion Region

The next congestion zone is associated with the red 138-kV buses at Wilson, Round Lake, Antioch, and, to a lesser extent, Gurnee. It is shown visually in Figures E.3-1 and E.3-2 in the far northeast part of the State, and in more detail in Figures F.1-32 and F.2.32. These high prices are always caused by a binding constraint on the Marengo-Pleasant Valley 138-kV line (with flow from Marengo to Pleasant Valley) for the ComEd 345-L15616-R contingency (loss of the Cherry Valley-Silver Lake 345-kV line).

The generators with the most sensitivity for controlling this constraint (on the constrained side) are Rocky Road owned by Dynegy, Elgin owned by Ameren-UE, Waukegan owned by

Midwest Generation, and Aurora owned by Reliant. Given the diversity of ownership, it is unlikely that this constraint could be exploited by a single company for profit maximization.

E.3.3.8 Gillespie Congestion Region

The Gillespie congestion zone, which is only significant for the Appendix F.2 case, is associated with the 138 kV buses at the Gillespie, N. Staunton, and to a lesser extent, the Litchfield substation. It is shown visually in Figures E.3-2 and F.2-33, immediately to the northeast of St. Louis. These high prices are always caused by a binding constraint on the N. Lac-Gillespie 138 kV line with the binding flow always from N. Lac to Gillespie. Most of the time (> 90%) this congestion is due to the Ameren AMRNMTL71A contingency (loss of the Coffeen-Roxford 345 kV line; this is also the IP95 contingency), with most of the other times due to the IP96 contingency (loss of the West Frankfort-Mt. Vernon 345 kV line).

This constraint tends to occur during lower load periods, when sensitive generators on the constrained side of the line are either on an outage, or not dispatched because of low system LMPs. These generators include Coffeen owned by Ameren-CIPS, the Holland Energy Center owned by Constellation Power, and Kincaid owned by Dominion Energy. Given the diversity of ownership, and the associated low load conditions, it is unlikely that this constraint could by exploited by a single company for profit maximization.

E.3.3.9 Northbrook Congestion Region

The Northbrook congestion zone is a localized problem that occurs for just a handful of hours. It is caused by an overload on the Northbrook-Dearfield 138-kV line (with flow going from Northbrook to Dearfield) during the 138-L15912_B_N contingency (loss of the parallel line from Northbrook to Dearfield) under very heavy load situations (> 30 GW) with a simultaneous outage of one of large Waukegan units. This results in very high LMPs on the Waukegan buses, greatly increasing total profits. During the few hours, this constraint that is binding Midwest Generation could probably increase profits by submitting high bids for the non-outaged Waukegan units.

To examine the extend to which Midwest Generation could increase its profits under high but not peak load conditions, the 90% of peak case was examined (again with the assumption that all Illinois units are in-service). The results of bid manipulation at Waukegan are shown in Table E.3-10. Once their bids exceed their existing bus LMP (multiplier equal 2), their net generation at Waukegan rapidly decreases, resulting in a reduced overall profit. For a range of bids, they seem to have about 45 MW of must-run generation at Waukegan, but there is a limit. For high enough bids, their net generation drops to zero, with overall decreased profits. So in general just modifying the Waukegan bids would not be profitable under the 90% of peak scenario. But the presence of the Northbrook Congestion region in the marginal cost studies indicates that for extremely high loads, coupled perhaps with other generator outages, Midwest Generation could profitably benefit from high bids at Waukegan.