4.1.2 Transmission System Loading

Case Study Assumptions

The components of the transmission system that are operated at their maximum capacity limits represent transmission congestion that can force the dispatching of generators out of the economic merit order, thus leading to higher electricity costs. Table 4.1.2-1 shows the components of the transmission network that were congested and the number of hours in the year this occurred. Figure 4.1.2-1 shows the location of these components.

It should be noted that these results do not consider any modifications to the transmission network topology that might be used by an ISO to relieve congestion (e.g., opening or closing circuits). The network topology used here, which was based on the National Electric Reliability Council (NERC) 2003 summer case as previously described, was static. It should also be noted that this set of constraints did not include consideration of the system contingencies discussed earlier. This basic analysis considered only the capacity limits of the equipment. Including contingencies would place more constraints on the transmission system. If limitations in the transmission system can be exploited by companies under these less constraining operating rules (i.e., without contingencies), it can be safely extrapolated that a higher degree of market power could be exercised when contingencies are considered. A more detailed transmission analysis that includes consideration of the contingencies is included in the PowerWorld analysis in Appendixes E and F.

The table shows that there were 65 transmission components that experienced capacity limits sometime during the year. A total of 22 are operated at their capacity limits for more 1% of the hours in a year. Nine were at capacity for more than 10% of the time, and 5 more than 20% of the time. These represented significant bottlenecks that can affect the movement of power. The following observations can be made from these results:

- *NI-A Zone*. The 345 kV Cordova line, which is a bus coupling, was operated at maximum capacity for over 2,300 hours per year. This is near the Quad Cities nuclear plant. The Dixon-Mendota 138-kV line was also at capacity for extended periods. These capacity limits affected power flows in the northwest portion of the State as well as interconnections with Iowa.

- *NI-B Zone*. There were only a few hours when lines in this zone were at capacity limits. As will be seen later, this does not necessarily mean that this zone is immune from the impacts of congestion.

- *NI-C Zone*. The 138-kV Crest Hill line was at its limit over 200 hours per year. This had an effect on the southwest portion of the Commonwealth Edison territory near Joliet.

- *NI-D Zone.* Several lines in this zone were loaded to capacity for extended periods. These limits had a significant effect on the flow of power through the central part of the City of Chicago.[14]

- *NI-E Zone.* The 345-kV line from Frankfort to Gooding Grove, just south of Chicago and east of Joliet, is at capacity for over 600 hours. This affects the movement of power into Chicago as well as to the surrounding areas.

- *NI-F Zone.* There are no lines at their capacity limits in this zone.

- *NI-G Zone.* The 138-kV Mazon-Oglesby line is operated at its maximum capacity for the majority of hours in the year.

- *IP-A Zone.* The capacity limits on the lines in this zone are reached less than 1% of the hours of the year.

- *IP-B Zone.* The 138-kV Kickapoo line is at capacity more than 300 hours per year. This is in the vicinity of the highly loaded Holland-Mason line described below.

- *IP-C Zone.* The 138-kV Sidney line (east central part of the State) and Gillespie line (northeast of St. Louis) are at capacity more than 100 hours per year.

- *AMRN-A Zone.* The lines loaded to capacity in this zone are at there limits for only a few hours per year.

- *AMRN-B Zone.* The Holland transformer is at capacity more than 2,200 hours per year. Also, the Coffeen-Pana 345-kV line, which is in the same vicinity, is at capacity almost 200 hours per year.

- *AMRN-D Zone.* The Gibson and Rantoul-Sidney 138-kV lines are at capacity for extended periods. These affect the area southeast of St. Louis.

- *AMRN-E Zone.* The Pinckneyville transformers are loaded to capacity over 1,000 hours per year. These limits affect the southern part of the State.

- *CILC Zone.* The Mason to Holland and Mason to Tazewell 138-kV lines are at capacity over 2,000 hours per year. These significant capacity limits affect power flows in the Peoria region.

- *EEI Zone.* The Joppa 161-kV line is at capacity almost 400 hours per year. This affects the southernmost portion of the State.

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[14] A number of improvements to the transmission system serving downtown Chicago have been implemented recently. These were not part of the 2003 NERC summer case used here. Also, there are a number of phase shifters used by Commonwealth Edison to manage power flow in the area. They are considered in an approximate way in the EMCAS simulation and in more detail in the PowerWorld simulation, as discussed in Appendixes E and F.

- *SIPC Zone.* The Baldwin-Campbell 138-kV line is operated at capacity more than 300 hours per year. This affects power flows southeast of St. Louis.

Conservative Assumptions

Table 4.1.2-2 shows the equipment operated at capacity limits using the Conservative Assumptions. For the most part, the same transmission equipment that was operated at capacity for extended periods under the Case Study Assumptions was also stressed under the Conservative Assumptions. Fifty components were operated at capacity limits at some point in the year, 19 for more than 1% of the time, 11 for more than 10%, and 2 for more than 20%. This indicates that the transmission limits constrained the operation of the power system even under these conservative assumptions.

Table 4.1.2-1 PC Case (Case Study Assumptions) Equipment Loadings

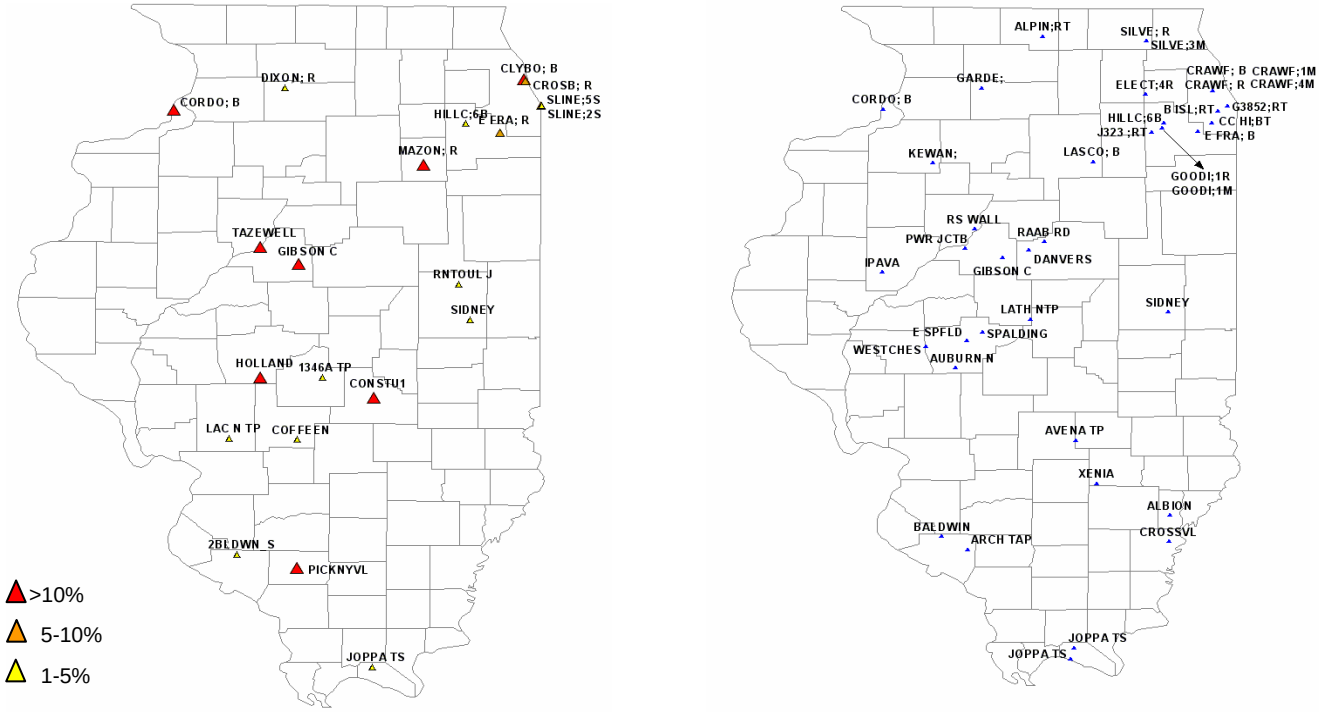
ID	Bus		Zone		Equipment			Hours Per Year Operated at Capacity
	From	To	From	To				
NI-A								
36284_37616	CORDO; B	CORDO;	NI-A	NI-A	345	kV	Line	2,329
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line	172
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line	39
36773_37076	GARDE;	H71 ;BT	NI-A	NI-A	138	kV	Line	11
36284_36362	CORDO; B	NELSO; B	NI-A	NI-A	345	kV	Line	1
NI-B								
37231_37371	SILVE; R	WILSO; R	NI-B	NI-B	138	kV	Line	11
36389_36067	SILVE; R	SILVE;3M	NI-B	NI-B	138	/345	Transformer	7
36067_37231	SILVE;3M	SILVE; R	NI-B	NI-B	138	/138	Transformer	7
NI-C								
36844_37362	HILLC;6B	WILL ;BT	NI-C	NI-E	138	kV	Line	272
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line	8
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line	8
NI-D								
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line	3,208
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line	508
36649_36691	CROSB; R	DIVER; R	NI-D	NI-D	138	kV	Line	448
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line	275
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer	12
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer	12
36294_36025	CRAWF; B	CRAWF;4M	NI-D	NI-D	138	/345	Transformer	3
36025_36640	CRAWF;4M	CRAWF; B	NI-D	NI-D	138	/138	Transformer	3
NI-E								
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line	608
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line	49
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line	23
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line	15
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer	10
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345	Transformer	10

Table 4.1.2-1 PC Case (Case Study Assumptions) Equipment Loadings

ID	Bus		Zone		Equipment			Hours Per Year Operated at Capacity
	From	To	From	To				
36451_36881	J323 ;RT	JO 9; R	NI-E	NI-E	138	kV	Line	3
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line	1
36308_36334	E FRA; B	GOODI;3B	NI-E	NI-E	345	kV	Line	1
NI-G								
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line	5,337
36891_37135	KEWAN;	POWER;	NI-G	NI-G	138	kV	Line	36
36922_36968	LASCO; B	MAZON; B	NI-G	NI-G	138	kV	Line	9
IP-A								
32411_37135	PWR JCTB	POWER;	IP-A	NI-G	138	kV	Line	43
32344_32379	RAAB RD	WASH ST	IP-A	IP-A	138	kV	Line	2
32344_32380	RAAB RD	ELPASO T	IP-A	IP-A	138	kV	Line	2
32343_32375	DANVERS	LILLY	IP-A	IP-A	138	kV	Line	1
IP-B								
32410_33159	1346A TP	KICKAPOO	IP-B	CILC	138	kV	Line	320
32358_32410	LATH NTP	1346A TP	IP-B	IP-B	138	kV	Line	16
IP-C								
32388_32405	SIDNEY	MIRA TAP	IP-C	IP-B	138	kV	Line	176
32291_32298	LAC N TP	GILSP TP	IP-C	IP-C	138	kV	Line	109
32388_32387	SIDNEY	SIDNEY	IP-C	IP-C	345	/138	Transformer	9
IP-D								
32285_32320	ARCH TAP	STEELVIL	IP-D	IP-D	138	kV	Line	82
32274_32327	BALDWIN	MT VRNON	IP-D	IP-D	345	kV	Line	2
AMRN-A								
30055_33315	AUBURN N	CHATHAM	AMRN-A	CWLP	138	kV	Line	24
30788_30789	IPAVA	IPAVA	AMRN-A	AMRN-A	138	/345	Transformer	1
AMRN-B								
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer	2,241
30395_31445	COFFEEN	PANA	AMRN-B	AMRN-B	345	kV	Line	191
30010_30439	ALBION	CROSSVL	AMRN-B	AMRN-B	138	kV	Line	47
30439_31351	CROSSVL	NORRIS	AMRN-B	AMRN-B	138	kV	Line	30
30072_31568	AVENA TP	RAMSEY	AMRN-B	AMRN-B	138	kV	Line	24
31993_32327	XENIA	MT VRNON	AMRN-B	IP-D	345	kV	Line	8
AMRN-D								
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line	1,227
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line	432
30614_32348	GIBSON C	BROKAW	AMRN-D	IP-B	138	kV	Line	12
AMRN-E								
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer	2,246
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer	1,468
30825_33394	JOPPA TS	JOPPA TS	AMRN-E	EEI	161	/345	Transformer	75
CILC								
33157_33175	HOLLAND	MASON	CILC	CILC	138	kV	Line	2,749
33141_33175	TAZEWELL	MASON	CILC	CILC	138	kV	Line	2,263
33002_33139	RS WALL	RSW EAST	CILC	CILC	138	/69	Transformer	11
33158_33307	E SPFLD	EASTDALE	CILC	CWLP	138	kV	Line	4

Table 4.1.2-1 PC Case (Case Study Assumptions) Equipment Loadings

ID	Bus From	Bus To	Zone From	Zone To	Equipment			Hours Per Year Operated at Capacity
EEI								
33394_33396	JOPPA TS	JOPTAPY	EEI	EEI	161	kV	Line	380
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line	49
SIPC								
33370_33373	2BLDWN_S	2CMPBL_S	SIPC	SIPC	69	kV	Line	303
CWLP								
33314_33315	SPALDING	CHATHAM	CWLP	CWLP	138	kV	Line	9
33312_33313	WESTCHES	WESTCHES	CWLP	CWLP	138	/69	Transformer	4



(a) Loaded to capacity limit equal to or more than 1% of the time

(b) Loaded to capacity limit up to 1% of the time

Note: For clarity, only one terminus (the From Bus) of each line is shown in each figure. Geographic locations are approximate.

Figure 4.1.2-1 PC Case (Case Study Assumptions) Transmission Components Operated at Maximum Capacity

Table 4.1.2-2 PC Case (Conservative Assumptions) Equipment Loadings

	Bus		Zone					Hours Per Year Operated at Capacity
ID	From	To	From	To	Equipment			
NI-A								
36284_37616	CORDO; B	CORDO;	NI-A	NI-A	345	kV	Line	4,482
36773_37076	GARDE;	H71 ;BT	NI-A	NI-A	138	kV	Line	665
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line	648
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line	44
36284_36362	CORDO; B	NELSO; B	NI-A	NI-A	345	kV	Line	34
37039_37171	NELSO; R	R FAL; R	NI-A	NI-A	138	kV	Line	7
NI-C								
36844_37362	HILLC;6B	WILL ;BT	NI-C	NI-E	138	kV	Line	986
36310_36362	ELECT; B	NELSO; B	NI-C	NI-A	345	kV	Line	149
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line	10
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line	2
NI-D								
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line	2,070
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line	610
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line	312
36649_36691	CROSB; R	DIVER; R	NI-D	NI-D	138	kV	Line	19
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer	12
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer	12
NI-E								
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line	1,400
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line	60
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line	30
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line	16
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345	Transformer	11
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer	11
NI-G								
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line	1,102
36891_37135	KEWAN;	POWER;	NI-G	NI-G	138	kV	Line	5
IP-A								
32411_37135	PWR JCTB	POWER;	IP-A	NI-G	138	kV	Line	5
IP-B								
32410_33159	1346A TP	KICKAPOO	IP-B	CILC	138	kV	Line	1,263
IP-C								
32388_32405	SIDNEY	MIRA TAP	IP-C	IP-B	138	kV	Line	958
32388_32387	SIDNEY	SIDNEY	IP-C	IP-C	345	/138	Transformer	63
AMRN-A								
30055_33315	AUBURN N	CHATHAM	AMRN-A	CWLP	138	kV	Line	50
31015_31559	MARBHD N	QUINCY S	AMRN-A	AMRN-A	138	kV	Line	1
30789_30990	IPAVA	MACOMB W	AMRN-A	AMRN-A	138	kV	Line	1
AMRN-B								
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer	1,351
30010_30439	ALBION	CROSSVL	AMRN-B	AMRN-B	138	kV	Line	250

Table 4.1.2-2 PC Case (Conservative Assumptions) Equipment Loadings

	Bus		Zone					Hours Per Year Operated at Capacity
ID	From	To	From	To	Equipment			
30439_31351	CROSSVL	NORRIS	AMRN-B	AMRN-B	138	kV	Line	168
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line	11
31993_32327	XENIA	MT VRNON	AMRN-B	IP-D	345	kV	Line	2
30395_31445	COFFEEN	PANA	AMRN-B	AMRN-B	345	kV	Line	1
30072_31568	AVENA TP	RAMSEY	AMRN-B	AMRN-B	138	kV	Line	1
AMRN-D								
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line	1,514
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line	33
AMRN-E								
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer	24
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer	24
30825_33394	JOPPA TS	JOPPA TS	AMRN-E	EEI	161	/345	Transformer	19
CILC								
33157_33175	HOLLAND	MASON	CILC	CILC	138	kV	Line	1,583
33141_33175	TAZEWELL	MASON	CILC	CILC	138	kV	Line	897
EEI								
33394_33396	JOPPA TS	JOPTAPY	EEI	EEI	161	kV	Line	869
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line	29
33392_33396	JOPPA S	JOPTAPY	EEI	EEI	161	kV	Line	7
CWLP								
33314_33315	SPALDING	CHATHAM	CWLP	CWLP	138	kV	Line	14
33312_33313	WESTCHES	WESTCHES	CWLP	CWLP	138	/69	Transformer	10

4.1.3 Locational Marginal Prices

While transmission capacity limits, shown in the previous section under both the Case Study and Conservative Assumptions, identify the points in the transmission system that are congested, they do not by themselves define the scope and magnitude of the situation, nor do they indicate how any company might exert market power by utilizing these limits. What is more significant than the limits themselves is how these limits affect prices at various points in the network (i.e., locational marginal prices [LMPs]). The price effects of the congestion may be evident in the vicinity of these heavily loaded components or they may be seen in much wider areas.

In identifying a particular bus in the network as possibly being affected by transmission congestion, the following indicators can be used:

- LMPs higher than surrounding areas, and
- Higher LMPs persisting for an extended period.

Under PC case conditions, in which there is no strategic bidding by GenCos (i.e., all are bidding production cost), these LMP indicators can provide an identification of where transmission congestion has its most significant price impacts. Figure 4.1.3-1 shows the criteria used to group the LMP indicators, for those buses that have either load or generators, into categories that might indicate the impacts of transmission congestion. The criteria can be interpreted by the following examples:

- If the LMP at the bus was always below 30 $/MWh, then it was coded blue.
- If the LMP was between 30 and 35 $/MWh for more than 80 hours per month (or 876 hours per year), the bus was coded yellow.
- If the LMP was between 35 and 45 $/MWh and if this was maintained for more than 8 hours per month (or 88 hours per year), it was coded yellow; if it was more than 80 hours per month (or 876 hours per year), it was coded orange.
- If the LMP was between 45 and 60 $/MWh, it was coded yellow; if this was maintained for more than 8 hours per month (or 88 hours per year), it was coded orange; if it was more than 80 hours per month (or 876 hours per year), it was coded red.
- If the LMP was over 60 $/MWh, it was coded orange; if this persisted for more than 40 hours per month (or 438 hours per year), it was coded red.

The LMP values and the hours of exceedance were chosen based on frequency distributions of LMPs seen under these conditions. These levels appear to be reasonable indicators of increasing prices due to increased load and transmission congestion.

Portion of Time LMP Was Exceeded							
(Fraction)	(Approximate Hours per Month)	(Hours per Year)	LMP				
			30	35	45	60	>60
.01	8	88					
.05	40	438					
.10	80	876					
>.10	>80	>876					

Figure 4.1.3-1 Criteria Used for Coding LMPs

Case Study Assumptions

Figure 4.1.3-2 shows the application of these criteria to the hourly LMPs calculated during each month of the simulation. Figure 4.1.3-3 shows the application on an annual basis.

The monthly results show that for about six months out of the year – January through March and October through December – the LMPs around the State were relatively constant. There was little transmission congestion and almost all the buses were coded blue. As the load increased in the warmer months – June, July, and August – much of the State showed an increase in LMPs. That most of the LMPs were in the same range (i.e., yellow), indicates that all paid higher prices as more expensive generation had to be dispatched to meet the increasing load. This was not the result of transmission congestion. It is the variations in color (i.e., into orange and red) that indicate the effects of transmission congestion, which caused price disparities across the State.

Comparing the locations of the buses showing higher than average LMPs (i.e., coded orange and red) to the locations of the capacity-loaded components of the transmission system shown in the previous section shows a degree of correlation. The following observations can be made:

- Buses in the City of Chicago were affected most by the limits on a number of transmission components. Higher LMPs were evident through the peak-load months. The impact of the capacity limits of the transmission equipment identified earlier (i.e., in the NI-D zone) are evident.

- Buses in the area north of Chicago and west out to the Iowa border also had higher LMPs than the rest of the State. The capacity limits on the nearby transmission components (i.e., in the NI-A and NI-D zones) caused higher prices, starting in June and continuing through September.

- A broad area stretching southwest of Chicago to Peoria and south to Springfield saw higher LMPs, but only during peak-load months. Transmission congestion did not impact these areas significantly in lower-load months.

- Smaller pockets of high LMPs were seen in the Sidney, Crossville, Joppa, and Pinckneyville areas due to the limits on local transmission components identified earlier.

As the load decreased through the fall and early winter, the situation returned to the condition where most of the State had LMPs in the blue range.

Table 4.1.3-1 shows the maximum monthly values of the LMPs for both the load and generator buses. Individual buses reached very high values. This reflects the value of generation at each bus as determined by the ISO's transmission-constrained scheduling algorithm (i.e., the SYSSCHED process described in Section 1.3).

It should be reemphasized that under PC case conditions there was no strategic bidding and GenCos priced their power at production costs. By this assumption, no market power was being exercised. Strategic bidding could be expected to amplify price differences between areas.

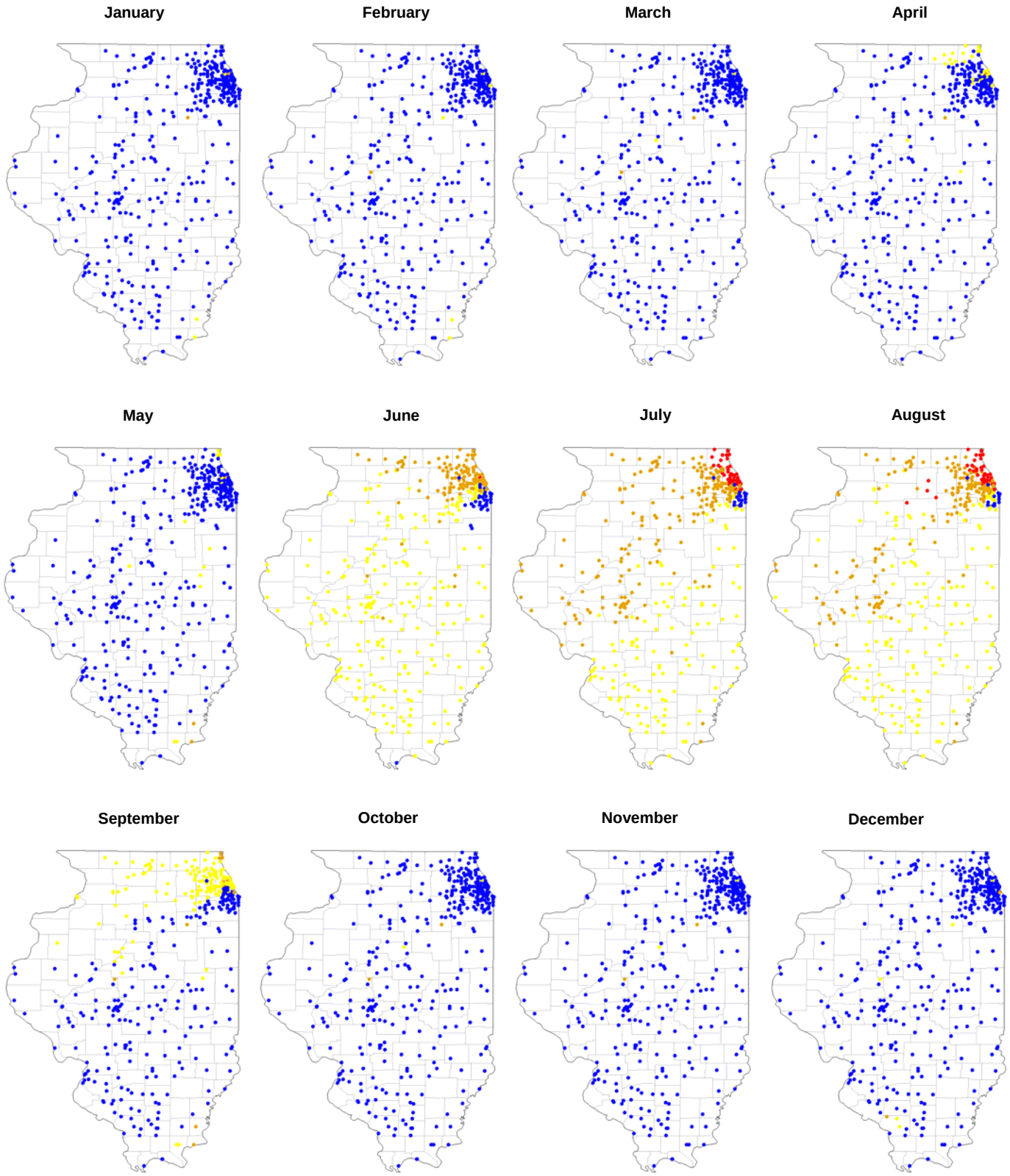


Figure 4.1.3-2 PC Case (Case Study Assumptions) Potential Load Pocket Identification Based on Monthly Data

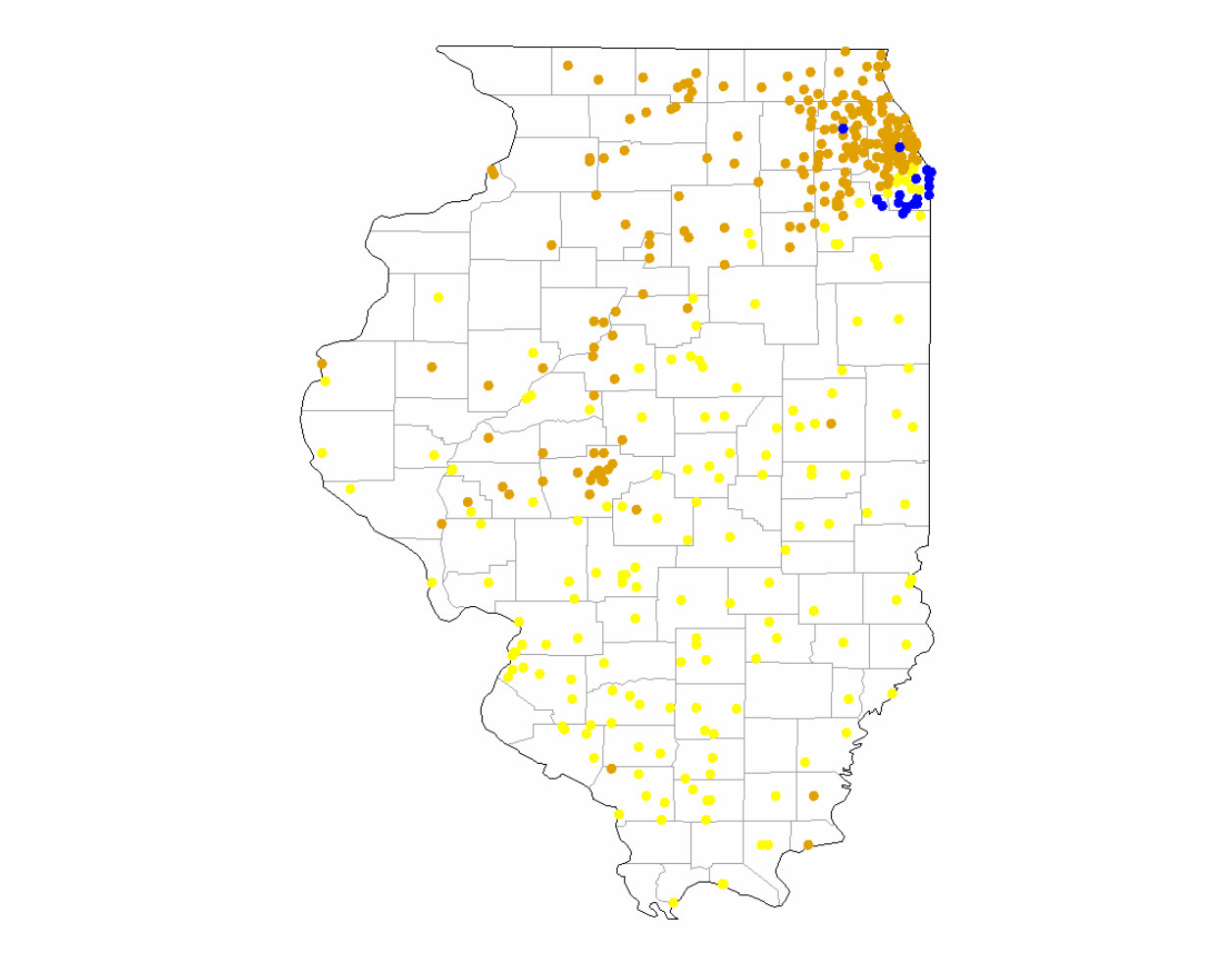


Figure 4.1.3-3 PC Case (Case Study Assumptions) Potential Load Pocket Identification Based on Annual Data

Table 4.1.3-1 PC Case (Case Study Assumptions) – Monthly Maximum LMPs at Generator and Load Buses

		Zone						
Month		NI-A	NI-B	NI-C	NI-D	NI-E	NI-F	NI-G
Jan	Max LMP	33.28	55.58	33.45	98.80	31.99	30.37	45.96
	Bus No.	36976	36684	36942	36624	36940	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	WILMI;	MAZON; R
Feb	Max LMP	30.76	44.27	32.01	71.11	30.83	30.51	45.27
	Bus No.	36976	36684	36695	36624	36745	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	DRESD; R	CLYBO; B	F CIT; R	WILMI;	MAZON; R
Mar	Max LMP	32.28	50.13	32.41	84.73	31.24	30.83	46.97
	Bus No.	36976	36684	36942	36624	36940	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	WILMI;	MAZON; R
Apr	Max LMP	33.02	57.47	34.75	104.84	31.62	32.54	52.28
	Bus No.	36976	36684	36695	36624	36940	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	DRESD; R	CLYBO; B	LISLE; B	WILMI;	MAZON; R
May	Max LMP	37.61	75.99	37.89	150.31	35.33	32.18	49.54
	Bus No.	36976	36684	36942	36624	36940	37659	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	KENDA;3C	MAZON; R
Jun	Max LMP	380.92	173.26	234.22	381.76	58.69	49.11	61.41
	Bus No.	36981	36684	37211	36624	36940	37659	36969
	Bus Name	MENDO;	DEVON;0B	SANDW; R	CLYBO; B	LISLE; B	KENDA;3C	MAZON; R
Jul	Max LMP	319.17	1,879.92	199.07	602.30	130.25	78.15	102.81
	Bus No.	36981	37371	37211	37317	36745	37659	37550
	Bus Name	MENDO;	WILSO; R	SANDW; R	WASHI; R	F CIT; R	KENDA;3C	POWER;6U
Aug	Max LMP	781.79	311.33	465.72	715.51	97.97	70.01	63.40
	Bus No.	36981	36684	37211	36624	36745	37659	36969
	Bus Name	MENDO;	DEVON;0B	SANDW; R	CLYBO; B	F CIT; R	KENDA;3C	MAZON; R
Sep	Max LMP	49.02	114.78	49.54	241.76	44.90	39.49	51.28
	Bus No.	36976	36684	36942	36624	36940	37659	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	KENDA;3C	MAZON; R
Oct	Max LMP	31.20	48.84	33.99	82.87	30.30	32.04	50.22
	Bus No.	36976	36684	36695	36624	36940	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	DRESD; R	CLYBO; B	LISLE; B	WILMI;	MAZON; R
Nov	Max LMP	35.09	62.97	35.29	117.03	33.45	31.24	45.28
	Bus No.	36976	36684	36942	36624	36940	37659	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	KENDA;3C	MAZON; R
Dec	Max LMP	32.42	54.00	32.73	95.85	34.91	31.09	47.33
	Bus No.	36976	36684	36695	36624	36745	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	DRESD; R	CLYBO; B	F CIT; R	WILMI;	MAZON; R

Color Coding

- LMP < 35 $/MWh
- 35 $/MWh ≤ LMP < 45 $/MWh
- 45 $/MWh ≤ LMP < 60 $/MWh
- LMP ≥ 60 $/MWh

Table 4.1.3-1 PC Case (Case Study Assumptions) – Monthly Maximum LMPs at Generator and Load Buses (Cont'd)

		Zone					
Month		IP-A	IP-B	IP-C	IP-D		CWLP
Jan	Max LMP	30.52	29.76	29.79	28.87		29.59
	Bus No.	32603	32273	32616	32675		33305
	Bus Name	EGAL #1	VERMILON	W TILTON	BLUFF CY		INTERSTA
Feb	Max LMP	29.73	30.67	29.75	30.83		29.20
	Bus No.	32615	32397	32660	32285		33315
	Bus Name	NORMAL E	MAHOMET	PORTR RD	ARCH TAP		CHATHAM
Mar	Max LMP	30.10	29.69	29.69	29.50		29.67
	Bus No.	32603	32273	32616	32675		33305
	Bus Name	EGAL #1	VERMILON	W TILTON	BLUFF CY		INTERSTA
Apr	Max LMP	29.90	29.28	29.20	29.11		29.33
	Bus No.	32603	32361	32362	32664		33306
	Bus Name	EGAL #1	ILLOP TP	N DEC W	EBELV 1		EASTDALE
May	Max LMP	33.20	55.44	32.45	32.60		32.00
	Bus No.	32603	32403	32651	32285		33315
	Bus Name	EGAL #1	PERKNSRD	SHRAM CY	ARCH TAP		CHATHAM
Jun	Max LMP	43.74	91.97	40.05	38.19		40.20
	Bus No.	32603	32403	32370	32675		33305
	Bus Name	EGAL #1	PERKNSRD	CATERPIL	BLUFF CY		INTERSTA
Jul	Max LMP	71.65	86.09	49.79	48.06		84.08
	Bus No.	32409	32403	32362	32664		33302
	Bus Name	ELKHART	PERKNSRD	N DEC W	EBELV 1		DALLMAN
Aug	Max LMP	50.71	63.92	51.06	46.71		51.50
	Bus No.	32409	32403	32370	32512		33305
	Bus Name	ELKHART	PERKNSRD	CATERPIL	HOOKDALE		INTERSTA
Sep	Max LMP	39.92	48.13	35.99	38.48		36.66
	Bus No.	32603	32403	32362	32675		33306
	Bus Name	EGAL #1	PERKNSRD	N DEC W	BLUFF CY		EASTDALE
Oct	Max LMP	29.33	28.80	28.78	28.75		28.83
	Bus No.	32603	32361	32304	32664		33306
	Bus Name	EGAL #1	ILLOP TP	AM STEEL	EBELV 1		EASTDALE
Nov	Max LMP	38.44	30.52	30.55	30.49		30.60
	Bus No.	32344	32361	32304	32664		33306
	Bus Name	RAAB RD	ILLOP TP	AM STEEL	EBELV 1		EASTDALE
Dec	Max LMP	31.69	32.64	30.95	29.52		30.50
	Bus No.	32615	32397	32370	32512		33305
	Bus Name	NORMAL E	MAHOMET	CATERPIL	HOOKDALE		INTERSTA

Color Coding

- LMP < 35 $/MWh
- 35 $/MWh ≤ LMP < 45 $/MWh
- 45 $/MWh ≤ LMP < 60 $/MWh
- LMP ≥ 60 $/MWh

Table 4.1.3-1 PC Case (Case Study Assumptions) – Monthly Maximum LMPs at Generator and Load Buses (Cont'd)

		Zone							
Month		AMRN-A	AMRN-B	AMRN-C	AMRN-D	AMRN-E	CILC	EEI	SIPC
Jan	Max LMP	30.12	29.36	28.71	29.88	30.86	29.95	29.54	73.43
	Bus No.	30018	30931	31503	31958	31383	33084	33484	33356
	Bus Name	AMOCO	LAWRNCVL	PICKVL 3	WATSEKA	ORDILL	TAZEWELL	JOPPA #4	2GALTN_S
Feb	Max LMP	29.65	31.60	30.23	39.37	32.40	62.46	30.79	59.86
	Bus No.	31115	30431	31501	31576	31383	33175	33484	33356
	Bus Name	MEPPEN	CRAB ORH	PICKVL 1	RANTOUL	ORDILL	MASON	JOPPA #4	2GALTN_S
Mar	Max LMP	29.84	29.63	29.40	29.71	29.67	77.70	29.66	30.05
	Bus No.	30018	31256	31501	31958	30004	33175	33484	33352
	Bus Name	AMOCO	MOWEAQUA	PICKVL 1	WATSEKA	ADM N AM	MASON	JOPPA #4	5RNSHW_S
Apr	Max LMP	29.67	29.15	29.06	48.60	29.19	29.54	28.99	29.51
	Bus No.	30018	31256	31501	31576	30004	33137	33485	33352
	Bus Name	AMOCO	MOWEAQUA	PICKVL 1	RANTOUL	ADM N AM	EDWARDS3	JOPPA #5	5RNSHW_S
May	Max LMP	33.04	33.39	32.21	48.14	33.32	43.63	32.62	69.43
	Bus No.	30018	31332	31501	31576	31383	33175	33484	33356
	Bus Name	AMOCO	NEWTON 1	PICKVL 1	RANTOUL	ORDILL	MASON	JOPPA #4	2GALTN_S
Jun	Max LMP	42.69	39.51	37.42	49.52	40.06	108.64	36.63	56.21
	Bus No.	30018	31256	31502	31576	30004	33175	33484	33356
	Bus Name	AMOCO	MOWEAQUA	PICKVL 2	RANTOUL	ADM N AM	MASON	JOPPA #4	2GALTN_S
Jul	Max LMP	76.37	51.06	47.34	49.87	49.60	386.30	46.63	67.90
	Bus No.	30022	30439	31501	31576	30004	33159	33484	33356
	Bus Name	AMOS_AM	CROSSVL	PICKVL 1	RANTOUL	ADM N AM	KICKAPOO	JOPPA #4	2GALTN_S
Aug	Max LMP	51.88	49.77	45.61	48.78	51.09	62.19	45.38	79.02
	Bus No.	30789	31256	31501	31576	30004	33175	33484	33356
	Bus Name	IPAVA	MOWEAQUA	PICKVL 1	RANTOUL	ADM N AM	MASON	JOPPA #4	2GALTN_S
Sep	Max LMP	38.70	42.97	34.34	49.94	35.92	110.64	35.07	80.02
	Bus No.	30018	30073	31502	31576	30004	33175	33484	33356
	Bus Name	AMOCO	AVENA	PICKVL 2	RANTOUL	ADM N AM	MASON	JOPPA #4	2GALTN_S
Oct	Max LMP	29.18	28.71	28.72	28.69	28.79	62.56	28.70	39.67
	Bus No.	30018	31807	31501	30613	31211	33175	33484	33373
	Bus Name	AMOCO	TAYLR NE	PICKVL 1	GIBSN G2	MISS	MASON	JOPPA #4	2CMPBL_S
Nov	Max LMP	31.50	30.39	30.40	37.49	30.57	78.78	30.29	73.98
	Bus No.	30018	31807	31501	31576	31211	33175	33484	33373
	Bus Name	AMOCO	TAYLR NE	PICKVL 1	RANTOUL	MISS	MASON	JOPPA #4	2CMPBL_S
Dec	Max LMP	30.59	30.26	29.42	43.04	30.97	57.25	29.37	74.91
	Bus No.	31054	31256	31501	31576	30004	33175	33484	33373
	Bus Name	MASON CY	MOWEAQUA	PICKVL 1	RANTOUL	ADM N AM	MASON	JOPPA #4	2CMPBL_S

Color Coding	
	LMP < 35 $/MWh
	35 $/MWh ≤ LMP < 45 $/MWh
	45 $/MWh ≤ LMP < 60 $/MWh
	LMP ≥ 60 $/MWh

Conservative Assumptions

Figures 4.1.3-4 and 4.1.3-5 show the results of using the Conservative Assumptions. These show the impact of transmission congestion in the Chicago area and the northern part of the State in July and August as in the Case Study Assumptions. For the other areas, the figures might be viewed as indicating that there is little effect of transmission congestion. However, as will be discussed later, the overall level of LMPs under Conservative Assumptions was significantly lower than under Case Study Assumptions. Thus, the color coding scheme used for the Case Study Assumptions (Figure 4.1.3-1) tends to understate the relative magnitude of variations in LMPs. Figure 4.1.3-6 shows a modified color coding scheme adjusted to reflect the lower overall prices under Conservative Assumptions. Figure 4.1.3-7 shows the annual LMP results with this modified scheme. These results show that the effects of transmission congestion under Conservative Assumptions are generally consistent with what was seen under Case Study Assumptions. The higher LMPs did not extend as far to the south and central parts of the State because of the increased generation available, but the rest of the State showed patterns very similar to those under the Case Study Assumptions.

4.1.4 Zonal Locational Marginal Prices

The previous section focused on the effects of transmission congestion on LMPs at specific buses in the network. This section focuses on the effects of the congestion on zonal LMPs, which have a direct relation to the prices consumers will pay for electricity.

LMPs were calculated for all buses in the network as part of the simulation. One set of buses had generators connected to them. The LMPs at these buses were used to determine the reimbursement to GenCos for the dispatch of their generators. Another set of buses had consumer load attached to them. These buses were grouped into the zones identified earlier. The load-weighted average LMPs for the buses in each zone were used to determine consumer payments. The LMPs for a third set of buses, which had neither generators nor loads attached, were included in the simulation calculations but are not displayed here, since they do not affect either GenCo revenues or consumer payments.

Case Study Assumptions

Figure 4.1.4-1 shows the monthly maximum and minimum values of the load-weighted LMP in each zone for the analysis year. It should be noted that the LMPs shown on the figure are load-weighted zonal averages, which are used to determine consumer charges. Individual nodes in the transmission network show even greater variation than what is shown as the zonal average.

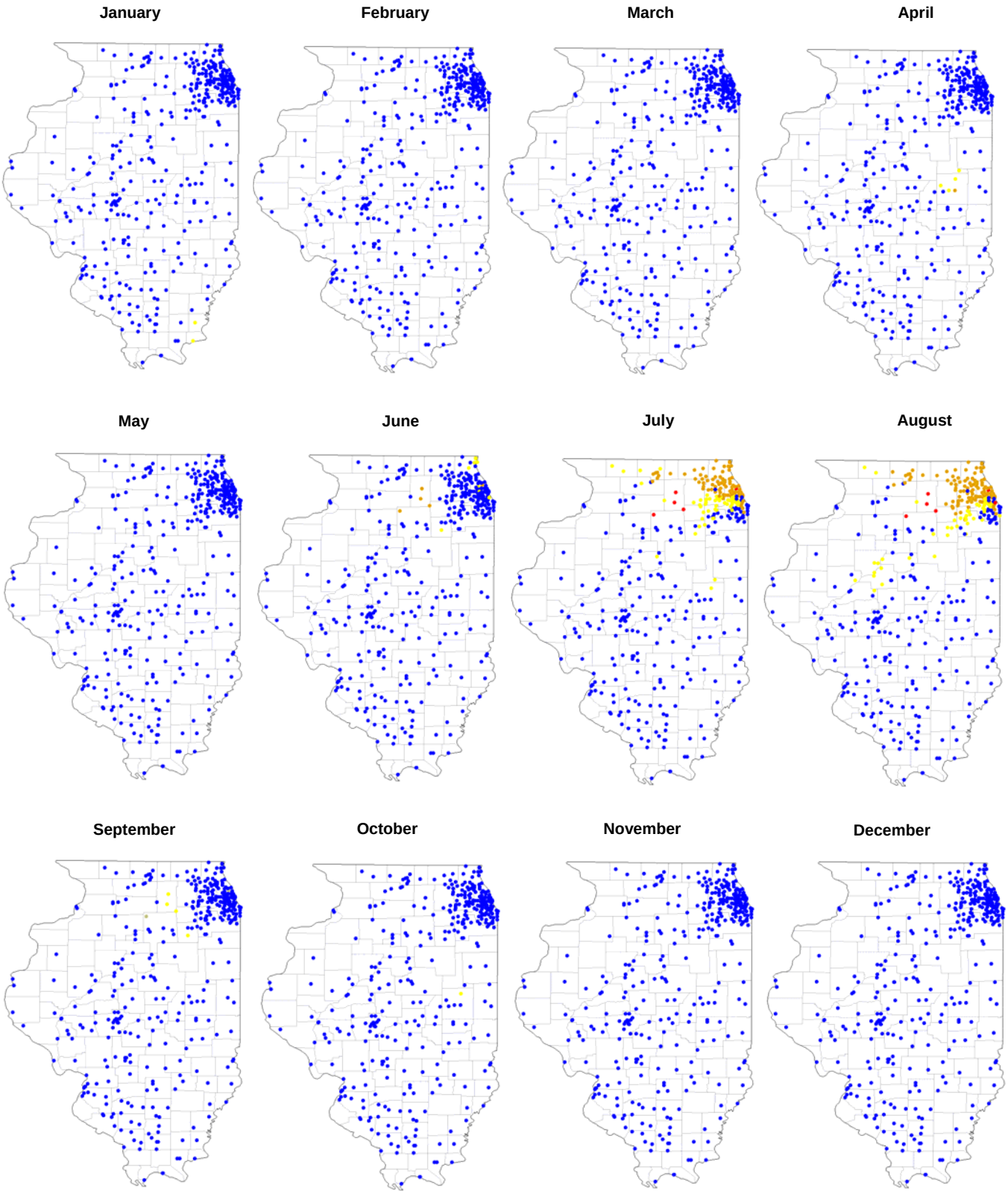


Figure 4.1.3-4 PC Case (Conservative Assumptions) Potential Load Pocket Identification Based on Monthly Data

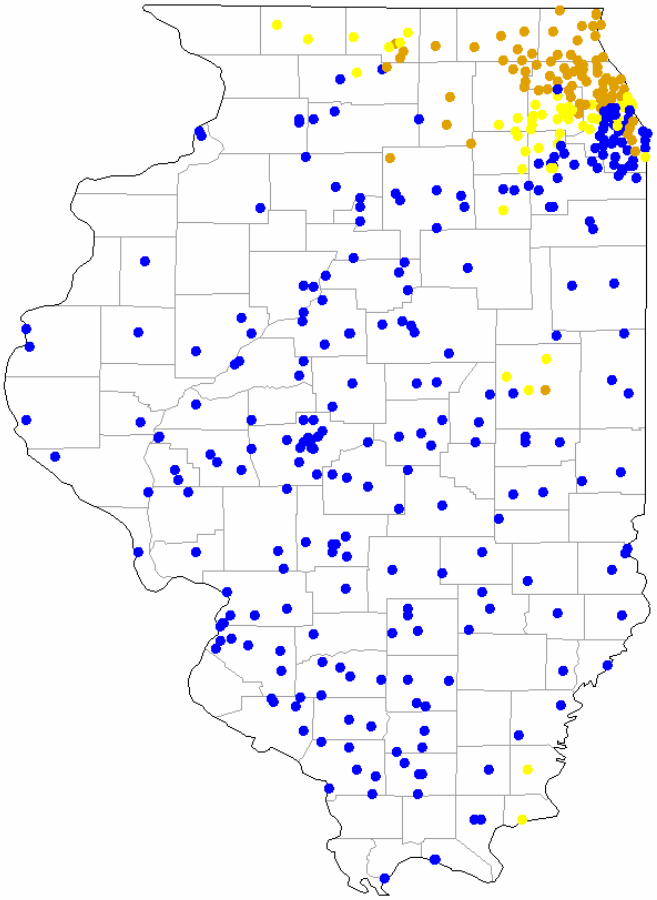


Figure 4.1.3-5 PC Case (Conservative Assumptions) Potential Load Pocket Identification Based on Annual Data

Portion of Time LMP Is Exceeded			LMP				
(Fraction)	(Approximate Hours per Month)	(Hours per Year)	20	25	30	50	
.01	8	88					
.05	40	438					
.10	80	876					
>.10	>80	>876					

Figure 4.1.3-6 Criteria Used for Coding LMPs – Modified for Conservative Assumptions

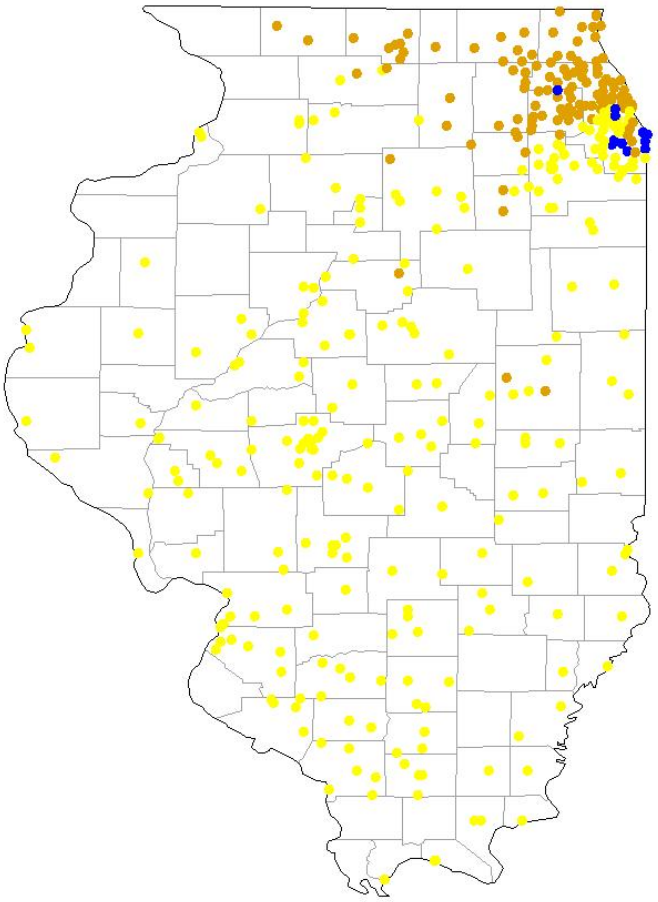


Figure 4.1.3-7 PC Case (Conservative Assumptions) Potential Load Pocket Identification Based on Annual Data – Modified Color Code Categories

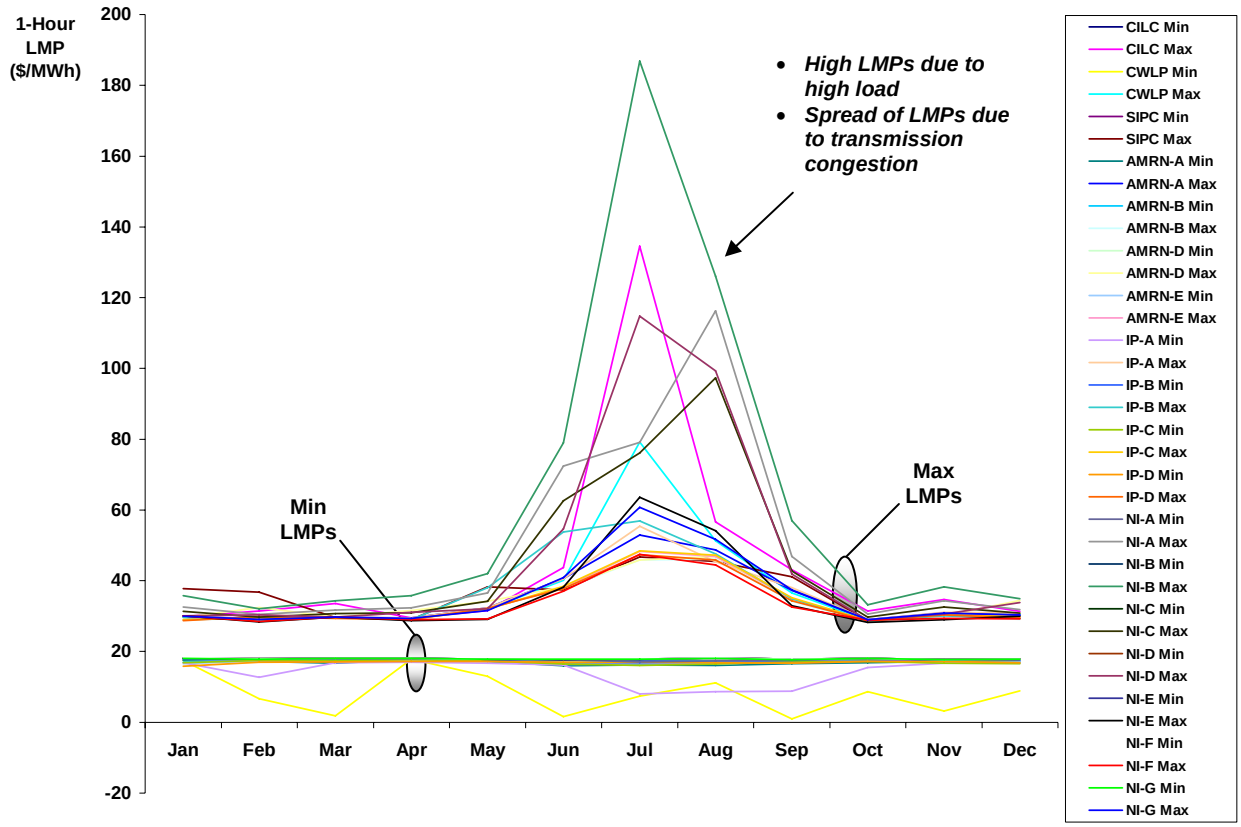


Figure 4.1.4-1 PC Case (Case Study Assumptions) Variation in Monthly Maximum and Minimum Load-Weighted Zonal LMPs

The variation in the zonal LMPs shows several distinct features:

LMPs increased in high load periods. As seen in the figure, LMPs increased across the State during high-load periods as more expensive generators were brought on-line to meet the load. This is seen as an increase in the maximum LMP in all zones in the June, July, August, and September periods. Even in the PC case, where there was no attempt to exercise market power by any company, the zonal LMPs were almost 10 times higher in high-load periods than they were during low-load periods.

LMPs varied across zones as a result of transmission congestion. During high load periods, the LMPs spread across the zones in the State. Were the LMPs to rise and fall together at the same rate, the indication would have been that there was no significant transmission congestion as all areas would have had nearly the same price at all times. However, as was described earlier, there were a number of points in the transmission system where equipment was loaded to capacity and constrained the movement of power. This caused the LMPs to vary across the zones. This was most evident in the June, July, August, September periods when the spread in the LMPs across the zones became significant. The transmission congestion described earlier forced the price higher in

some areas than in others. The variation across the State results in LMPs in the northern part of the State reaching almost five times higher than elsewhere.

Transmission congestion created higher LMPs even during non-peak hours. The figure shows several times where the LMPs became higher or lower across the State even in the lower-load months. This was the result of the scheduled and forced outage scenario used in the PC case using Case Study Assumptions, where some generators in these zones were assumed to be out of service. In these areas, this loss of generation capacity could not be readily made up by other, less expensive units due to transmission limits. More expensive units had to be brought on-line to meet the load.

To gain a more detailed look at the occurrence of higher LMPs, Table 4.1.4-1 shows the statistical variation in the zonal LMPs, and Figure 4.1.4-2 shows a frequency distribution of load-weighted LMPs in each zone. In most areas of the State, the LMPs were in the range of 20-28 $/MWh for 90% of the time over the course of a year. As shown on the expanded scale, about 5% of the time the higher loads caused LMPs to rise together due to a small amount of transmission congestion. For about 1% of the time (about 88 hours per year), the increasing transmission congestion caused LMPs to rise considerably and to vary significantly from zone to zone. LMPs across the State rose above 100 $/MWh, as shown in the table. This distribution shows that, in general, the hours where high LMPs would be experienced are relatively few under PC case conditions; however, during these hours, the LMPs can be significantly higher and can show wide variability across the State.

Table 4.1.4-1 PC Case (Case Study Assumptions) – Statistical Variation in LMPs

	Load-Weighted Locational Marginal Price ($/MWh)		
Zone	**Mean**	**Median**	**Maximum**
NI-A	21.7	19.0	116.3
NI-B	22.4	19.2	186.9
NI-C	21.6	19.2	97.4
NI-D	21.5	19.2	114.8
NI-E	21.0	19.2	63.6
NI-F	21.0	19.3	47.5
NI-G	21.2	19.1	60.7
IP-A	20.0	18.4	55.5
IP-B	20.7	18.8	56.9
IP-C	20.5	18.6	48.4
IP-D	20.4	18.6	47.4
AMRN-A	20.6	18.7	52.9
AMRN-B	20.5	18.7	46.0
AMRN-D	20.7	18.8	46.9
AMRN-E	20.5	18.6	48.3
CILC	21.3	19.2	134.5
SIPC	20.8	18.8	46.7
CWLP	20.3	18.4	79.2

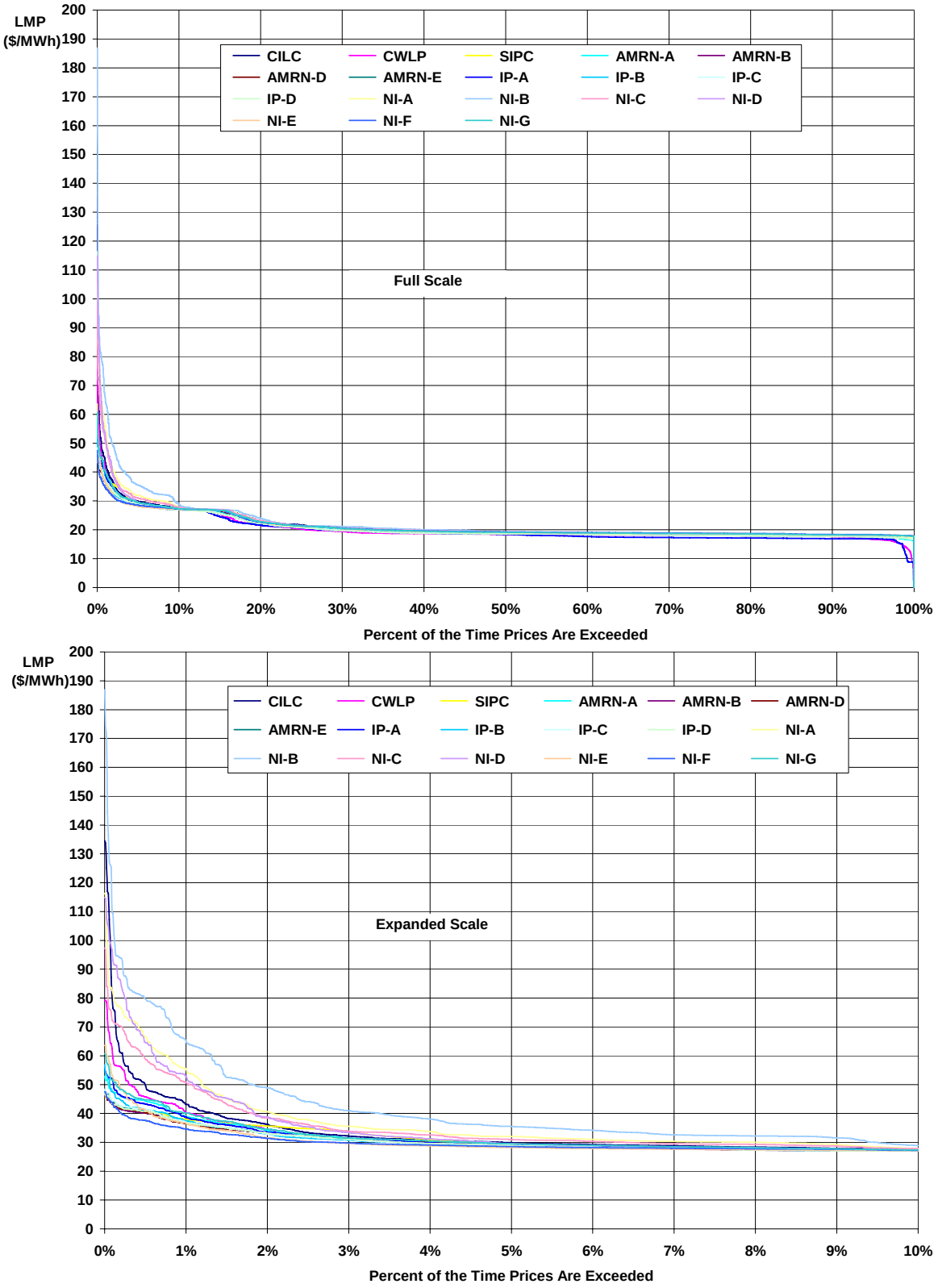


Figure 4.1.4-2 PC Case (Case Study Assumptions) Frequency Distribution of Load-Weighted LMPs by Zone

Figure 4.1.4-3 shows the hourly load-weighted average LMPs by zone for two months of the analysis year: April, which was a low-load month, and July, which was a high-load month. As a point of reference, the statewide load for each month is also shown. The results show the variation in LMP that follow hourly and weekly variations in load.

During low-load periods, the LMPs were relatively uniform throughout the State. The LMPs in northern Illinois average about 10-15% higher. Under low-load conditions, the transmission congestion (i.e., caused by components operated at their capacity limits) was not a major issue. Even with the forced outages and the congestion in the PC case, there was ample generation and transmission capacity to keep LMPs relatively low and geographically constant. During high-load periods, the LMPs increased in both magnitude and variability.

The transmission congestion results discussed in the previous section can be compared with the LMP results, and the following observations can be made:

- The NI zones all showed the effects of transmission congestion with LMPs that were measurably higher than elsewhere in the State. It can be seen that the effects of the congestion extended well beyond the immediate vicinity of the heavily loaded equipment. For example, in the area north of Chicago (i.e., the NI-B zone) there were only a few system components loaded to capacity for a few hours per year. Nevertheless, it had the highest mean value of LMP and the highest maximum value. Congestion in the adjacent NI-A zone (northwest portion of the State) and NI-D zone (Chicago) affected prices in this zone.

- The IP, AMRN, and SIPC zones had the lowest LMPs in the State. In the case of AMRN, this was true even though some equipment was consistently heavily loaded (e.g., Holland transformer, Gibson 138-kV line, Pickneyville transformers). Since the congestion had a smaller effect on prices, these zones were less likely to be impacted by market power effects, since there were other relatively low-cost generation options that could supply the load.

- The CILC zone had high LMPs resulting from congestion on the Holland-Mason-Tazewell lines. The LMPs were in the same range as the NI zones. This zone could be open to the exercise of market power because of these limits and their impact on prices.

- The CWLP zone showed some congestion effects that were intermediate to the other zones and for fewer hours.

- The NI and CILC zones could be considered the most vulnerable to the exercise of market power due to transmission congestion.

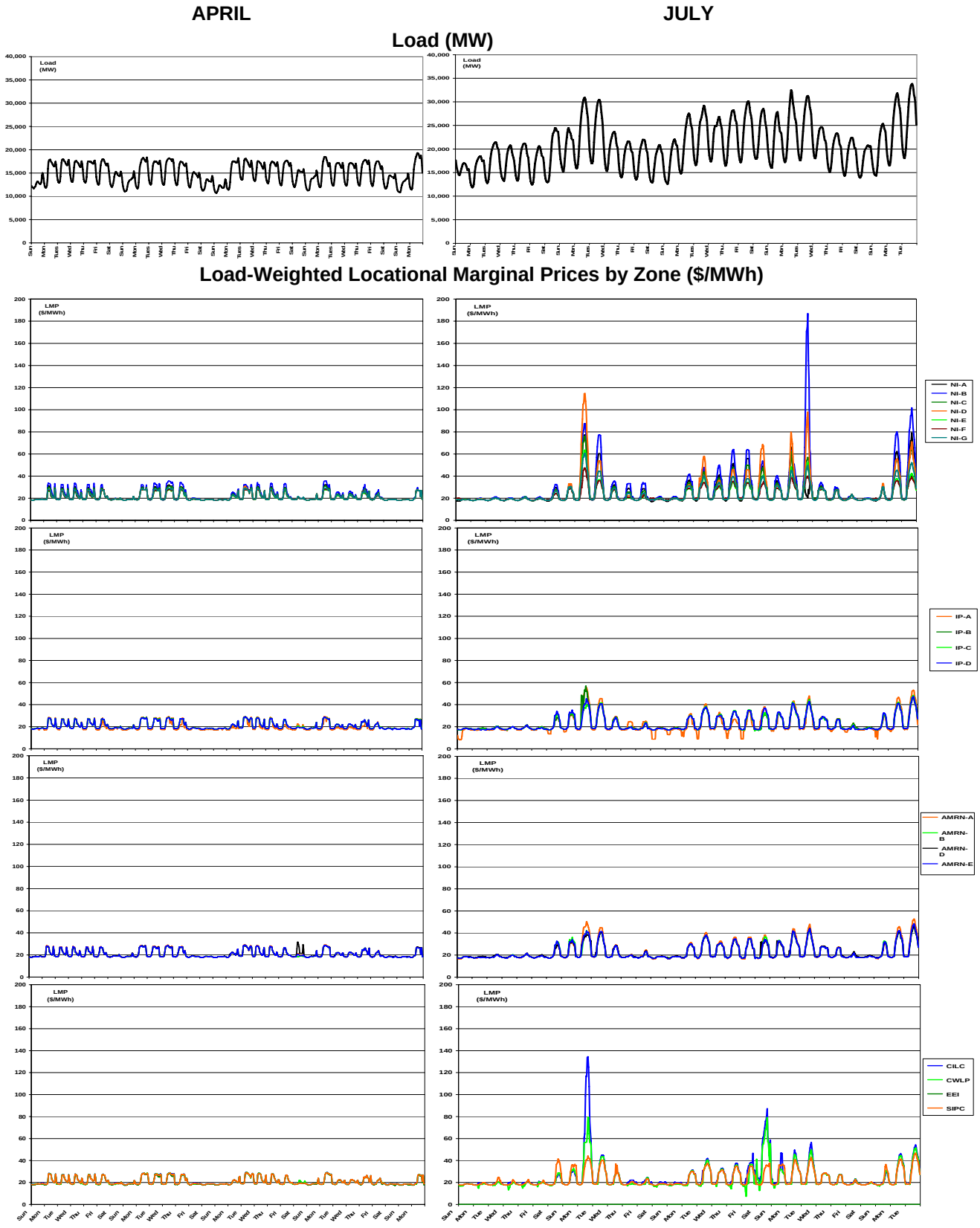


Figure 4.1.4-3 PC Case (Case Study Assumptions) Load-Weighted Zone LMPs for April and July

Conservative Assumptions

Figures 4.1.4-4 and 4.1.4-5 show the effect on LMPs of using the Conservative Assumptions. The elimination of FOM from production cost, the elimination of forced outages, and the dropping of the company-level unit commitment process resulted in the LMPs statewide being measurably lower under these assumptions than under the Case Study Assumptions. Under Case Study Assumptions, the LMPs tended to average about 20-28 $/MWh during most hours and peak at about 190 $/MWh. Under Conservative Assumptions, they averaged about 13-16 $/MWh for most hours with a peak at 80 $/MWh. This result is expected, since the Conservative Assumptions make more capacity available and that capacity is bid into the market at lower prices (i.e., without the FOM added).

Despite these lower prices, the pattern of increasing LMPs during peak months and an increase in the spread of prices due to transmission congestion remained, even under Conservative Assumptions. Having the additional generation capacity available using these assumptions did not completely eliminate the effects of transmission congestion. Prices in the northern part of the State were still more than double those elsewhere due to this congestion.

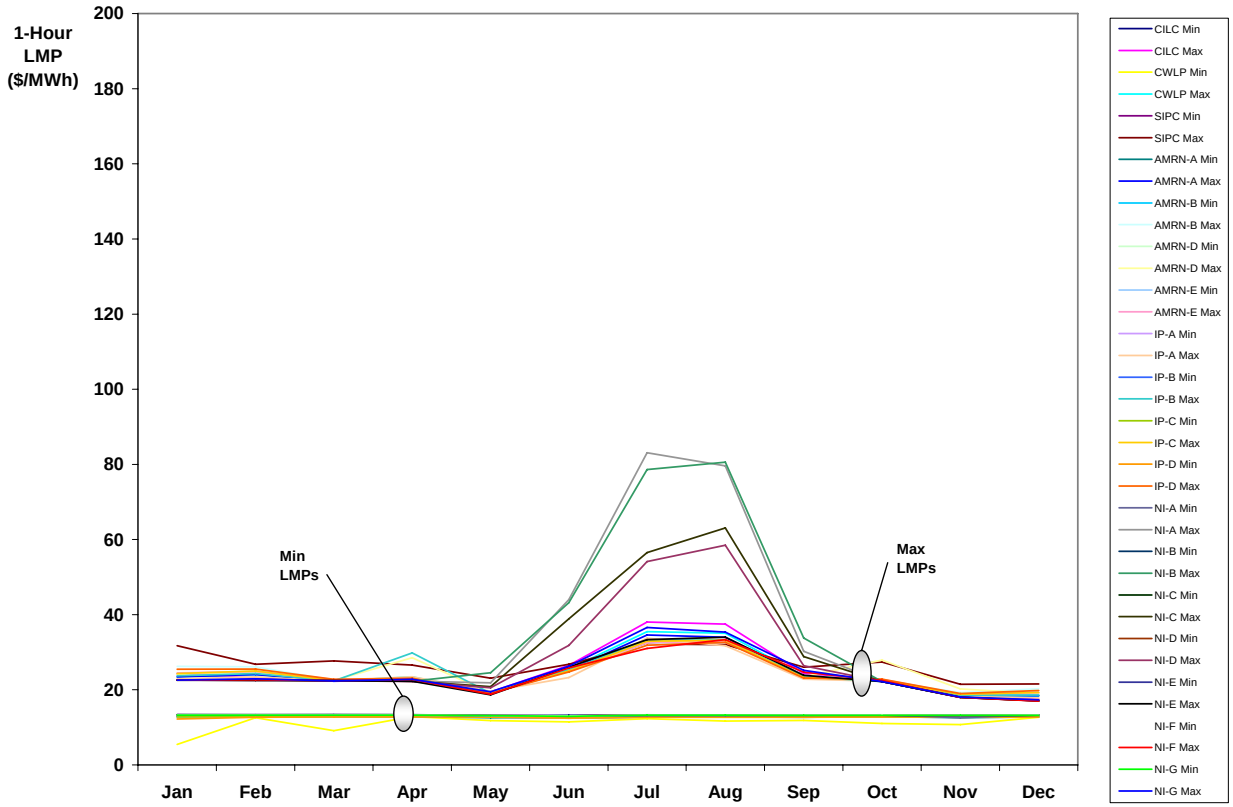
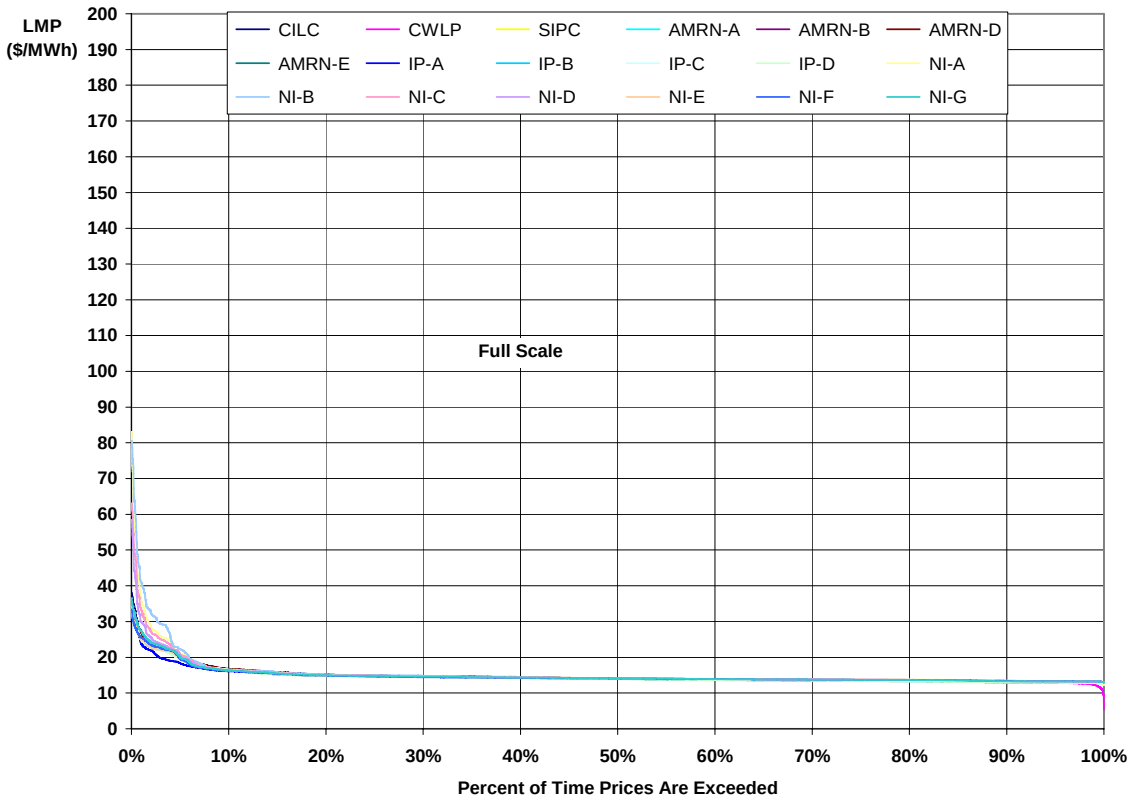


Figure 4.1.4-4 PC Case (Conservative Assumptions) Variation in Monthly Maximum and Minimum Load-Weighted LMPs



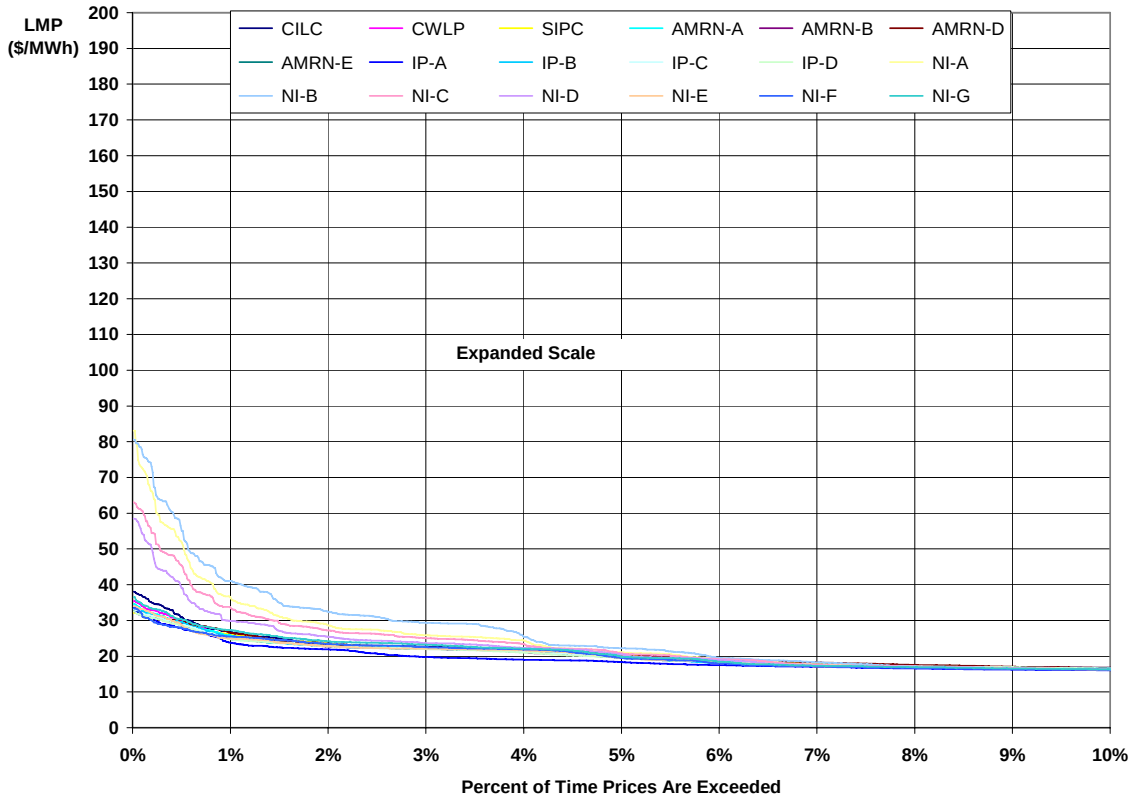


Figure 4.1.4-5 PC Case (Conservative Assumptions) Frequency Distribution of Load-Weighted LMPs by Zone

4.1.5 Generation Dispatch

Case Study Assumptions

Figure 4.1.5-1 shows the simulation results for the dispatching of generation to meet load for each hour of the year. The figure shows the generation from in-state sources only. Throughout the year there was more than enough generation to meet the in-state load, as well as enough to make the State a net exporter under PC case conditions using the Case Study Assumptions. At any hour and at any of the interties with surrounding systems, the power flow may be either into or out of the State, as Illinois companies will import power if it is economically competitive. On an annual basis, the State exported about 6% of its electricity generation, which is somewhat lower than historical values (19% in 2001, as discussed earlier). The GenCos in the State remained competitive with out-of-state suppliers.

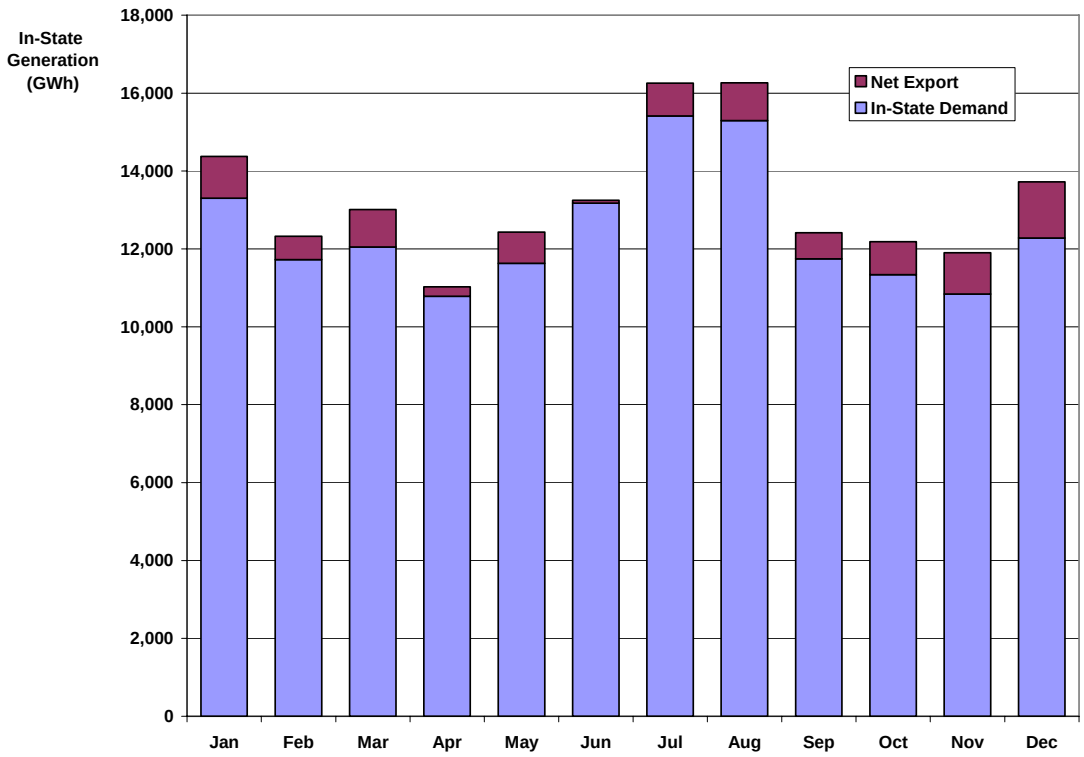


Figure 4.1.5-1 PC Case (Case Study Assumptions) In-State Generation and Exports

Figure 4.1.5-2 shows the distribution of the generation throughout the State over the year. In the simulation about 60% of the State's generation came from facilities located in the northern part of the State. Figure 4.1.5-3 shows the generation by fuel type throughout the year. Nuclear and coal units dominated the supply in the State. Only about 2% was from natural gas or other sources. This is especially significant since much of the new generation capacity that has been installed in the State in the last decade has been natural-gas-fired. All of the new capacity assumed to be installed up through the analysis year was also gas-fired. The results indicate only a limited use of the gas-fired units, even with the relatively low natural gas prices used for the

PC case analysis. This pattern is consistent with historical data. The Energy Information Administration reported that in 2001 only 1.1% of the electricity generated in the State was from natural gas.[15] The large increase in gas-fired capacity did not alter that under PC case conditions.

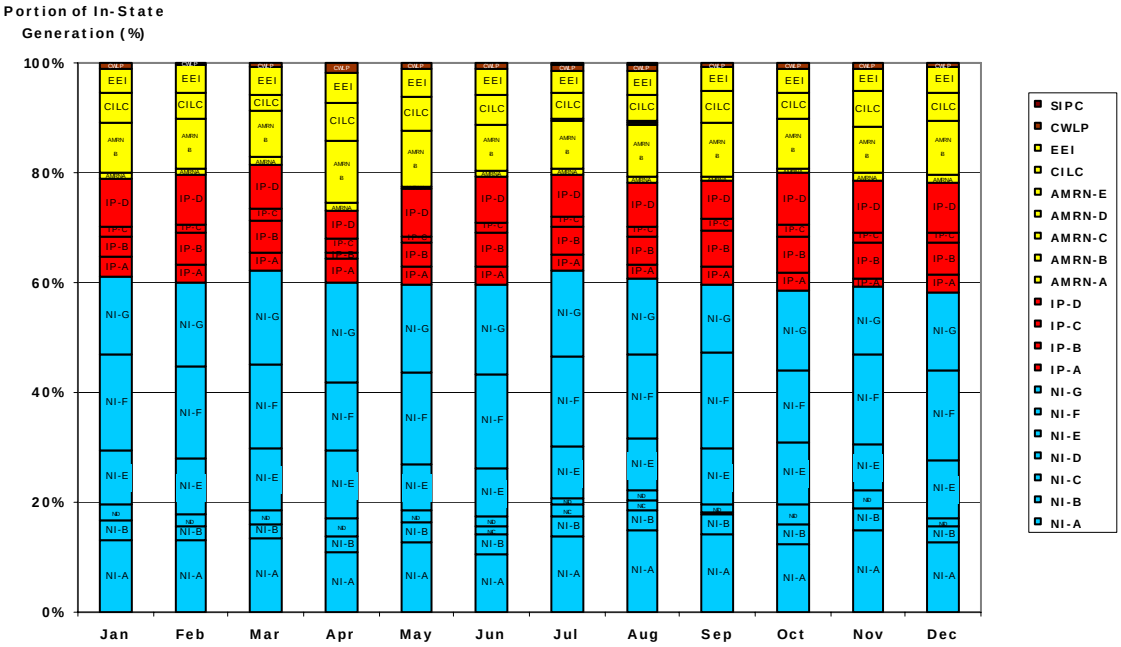


Figure 4.1.5-2 PC Case (Case Study Assumptions) In-State Generation by Zone

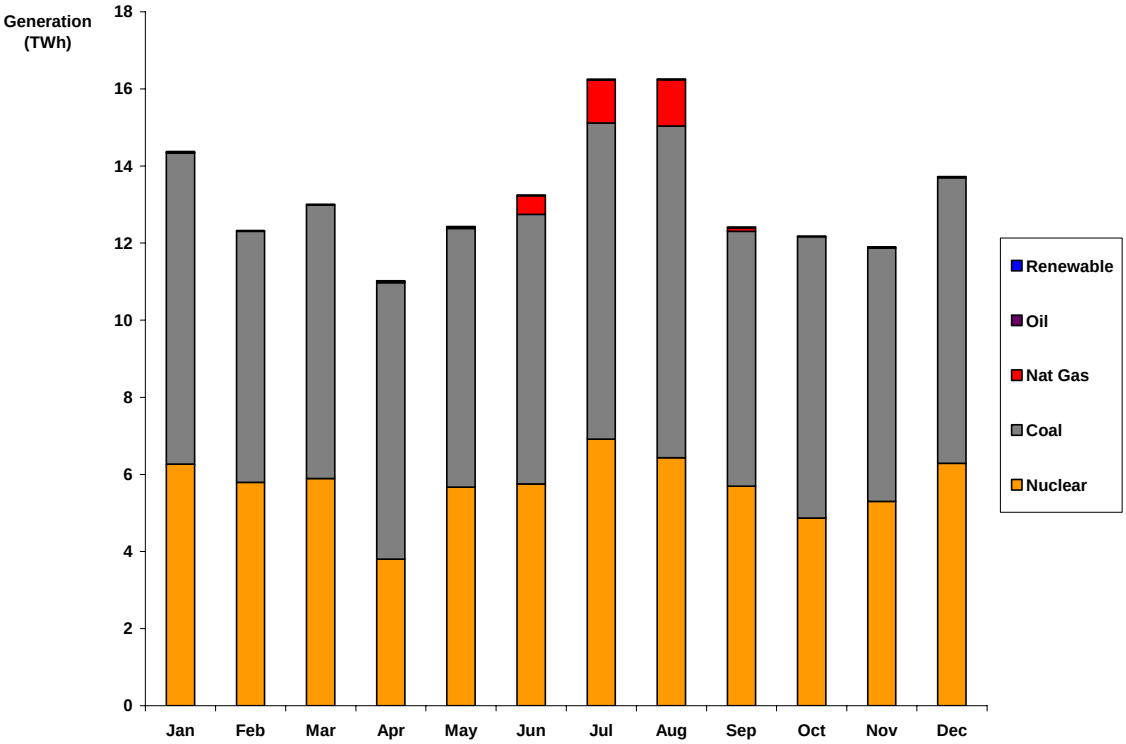


Figure 4.1.5-3 PC Case (Case Study Assumptions) In-State Generation by Fuel Type

[15] See http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls.

Conservative Assumptions

Figure 4.1.5-4 shows the results of the PC case when the Conservative Assumptions were used. While the general pattern of in-state generation is similar to that under the Case Study Assumptions, the level of generation by in-state GenCos was reduced and the State was a net importer of electricity. Under these assumptions, the State imported about 15% of its electricity on an annual basis.

Under Conservative Assumptions, the exclusion of forced outages made more generation capacity available from both in-state and out-of-state suppliers. Likewise, the elimination of the FOM as part of the production cost, lowered the cost of both in-state and out-of-state suppliers. The results show that out-of-state suppliers were more economically competitive under the Conservative Assumptions and captured a higher market share of the generation. As noted earlier, the State has historically been a net exporter of electricity. The results based on using the Conservative Assumptions deviate from this historical pattern.

Figure 4.1.5-5 shows the generation by fuel type for the PC case using the Conservative Assumptions. The pattern is similar to that under the Case Study Assumptions; that is, nuclear and coal dominated the generation, with natural gas providing only a small portion during peak months. Gas provided only about 1% of the annual generation under these assumptions.

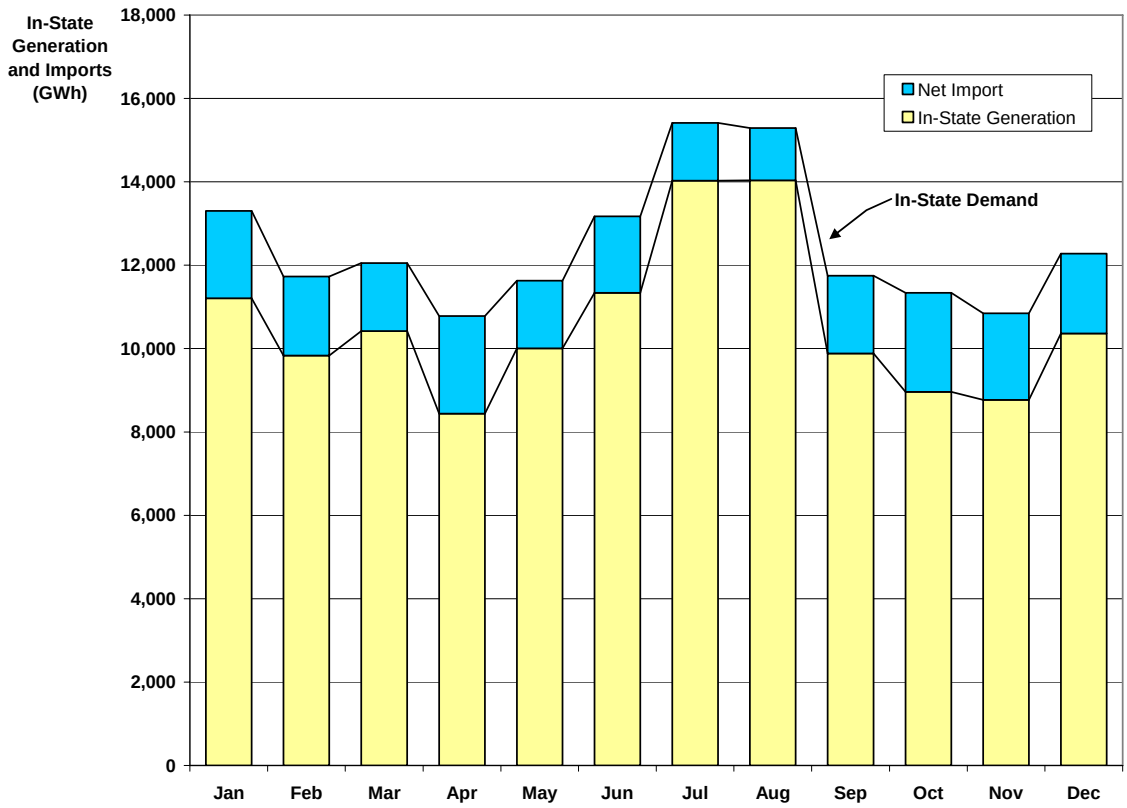


Figure 4.1.5.-4 PC Case (Conservative Assumptions) In-State Generation and Imports

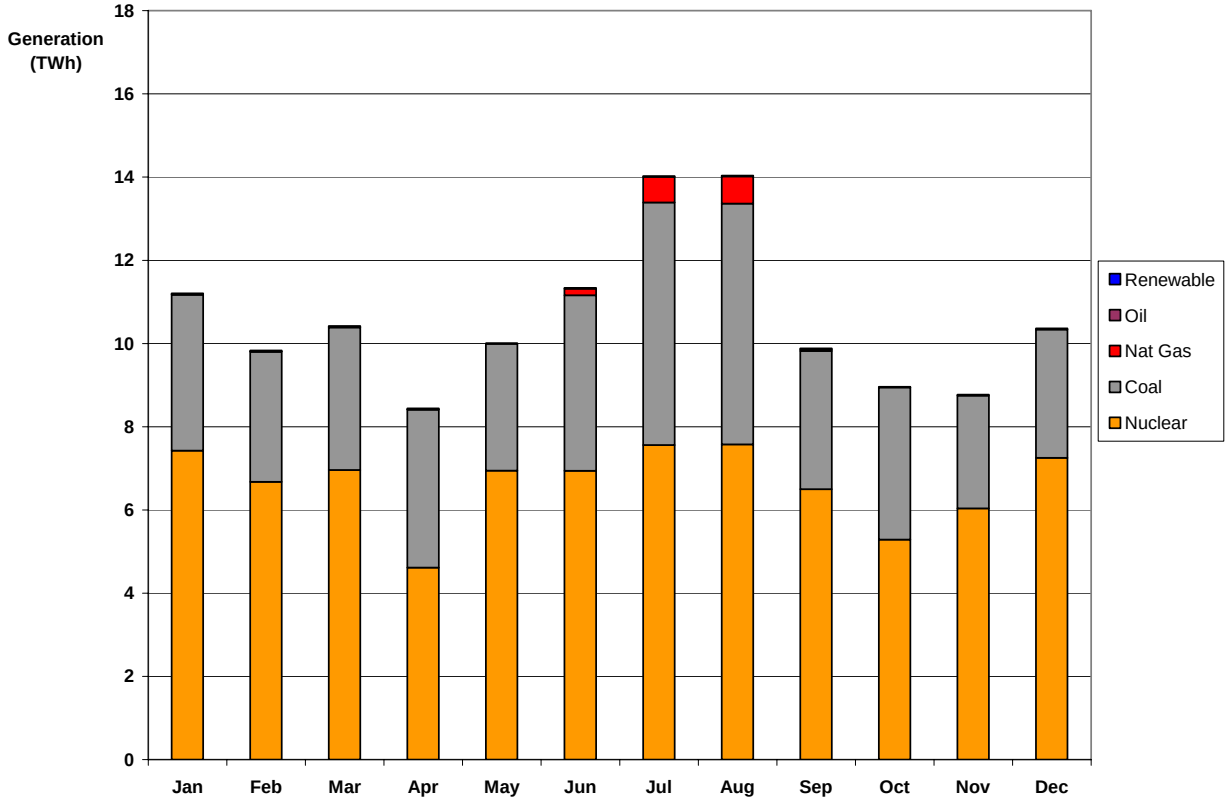


Figure 4.1.5-5 PC Case (Conservative Assumptions) In-State Generation by Fuel Type

4.1.6 Agent Results

The PC case results for each of the agents that are participants in the electricity market are discussed in the next sections.

Generation Companies – Case Study Assumptions

Figure 4.1.6.-1 shows the monthly generation in the analysis year for each company operating in Illinois. Figure 4.1.6-2 shows the market share of each company based on annual generation. Table 4.1.6-1 shows the HHI computed on this same basis. The figures and the table illustrate the concentration in the State generation market under PC case conditions. Exelon Nuclear captured 43% of the annual generation in the State. Four other companies, Ameren, Dominion Energy, Dynergy Midwest Generation, and Midwest Generation LLC, accounted for most of the balance. The five companies together accounted for about 97% of the State generation in the PC case.

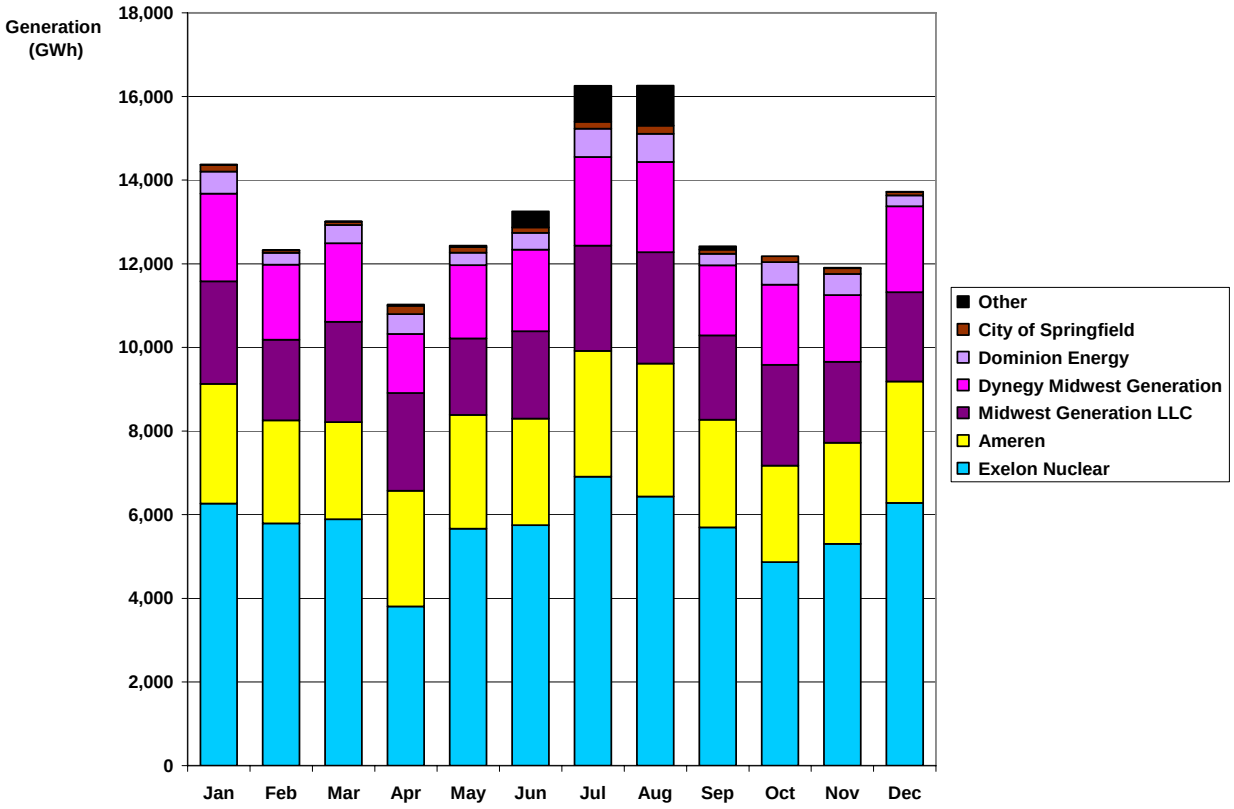


Figure 4.1.6-1 PC Case (Case Study Assumptions) Generation by Company

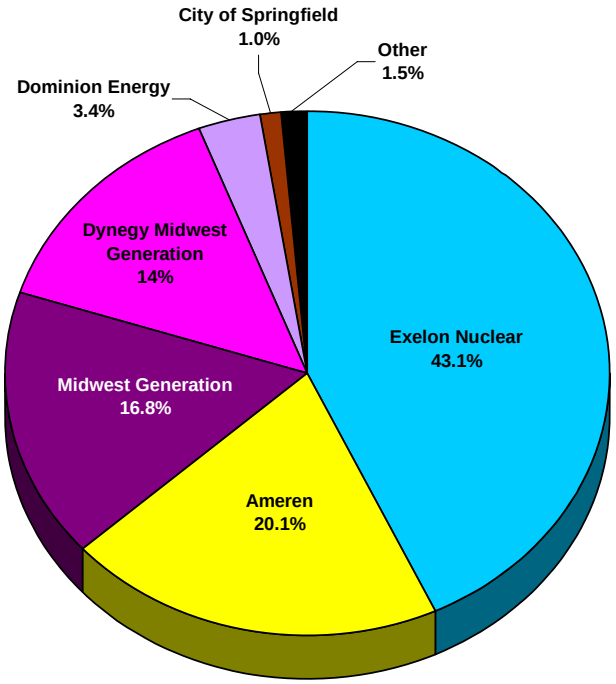


Figure 4.1.6-2 PC Case (Case Study Assumptions) GenCo Market Share of Annual GWh of Generation

Table 4.1.6-1 PC Case (Case Study Assumptions) Generation Company Market Share

	Annual Generation (GWh)						
Generation Company	**Nuclear**	**Coal**	**Natural Gas**	**Oil**	**Other**	**Total**	**Market Share of Annual GWh of Generation**
GenCo – Exelon Nuclear	66,313					66,313	41.7%
GenCo – Ameren		31,567	255	1	244	32,066	20.1%
GenCo – Midwest Generation LLC		26,665	23	5		26,693	16.8%
GenCo – Dynegy Midwest Generation		22,360				22,402	14.1%
GenCo – Dominion Energy		4,955	414			5,369	3.4%
GenCo – Exelon Nuc/Midamer Energy	2,362					2,362	1.5%
GenCo – City of Springfield		1,581	2			1,583	1.0%
GenCo – NRG Energy			741			741	0.5%
GenCo – Reliant Energy			379			379	0.2%
GenCo – Calpine			290			290	0.2%
GenCo – Constellation Power			191			191	0.1%
GenCo – Duke Energy			174			174	0.1%
GenCo – Southern Illinois Power Coop.		110	28			138	0.1%
GenCo – Dynegy/NRG Energy			116			116	0.1%
GenCo – MidAmerican Energy Co.			112			112	0.1%
GenCo – Allegheny Power			80			80	0.1%
GenCo – Aquila Energy			52			52	0.0%
GenCo – PPL			47			47	0.0%
GenCo – Power Energy Partners			30			30	0.0%
GenCo – Soyland Power Coop Inc.		6	12			18	0.0%
GenCo – Calumet Energy LLC							0.0%
GenCo – Southwestern Electric Coop.							0.0%
Total	**68,675**	**87,243**	**2,986**	**6**	**244**	**159,154**	**100.0%**
HHI – based on total generation							**2,636**
HHI – based on coal-fired generation							**2,936**
HHI – based on natural-gas-fired generation							**1,257**

In evaluating the market power potential of the generation companies, some of the various indices mentioned earlier were considered. The HHI base on total generation was in excess of 2,600, which indicates a highly concentrated market for electricity generation. The FERC 20% benchmark test shows that both Exelon Nuclear and Ameren had the 20% market share, with Midwest Generation and Dynegy a little lower. Applying the FERC residual supply index approach, the State's peak load could not be met if all of the capacity from any of the top market share holders were not available. Thus, by several measures, the generation market in the State can be considered to be concentrated.

Looking at the HHI based on fuel type shows that the coal-fired generation was highly concentrated. Three companies, Ameren, Midwest Generation, and Dynegy, accounted for 92% of the generation produced by coal plants. For nuclear generation, the market belonged entirely to Exelon Nuclear and its joint ownership venture with MidAmerican. For natural gas units, the HHI indicated a moderately concentrated market with the annual generation spread among a number of companies. The implication is that all of the State's low-cost generation in the form of nuclear and coal units, which had dominant market share when production cost bidding was used, is concentrated in the ownership of a few companies. Even the higher-cost natural gas units showed a moderate degree of concentration in such a market.

It should be recalled that in this study the generation market, in which the GenCos competed and in which the various indices of market power were computed, includes the entire State of Illinois. All suppliers could offer to meet any demand in the State with the choice subject to the price competitiveness and transmission limits. Out-of-state markets (both load and supply) were represented in simplified form, but out-of-state suppliers competed on the same basis as in-state suppliers, subject to the limits of the transmission system interties. On this basis, the determination of a statewide value of the various market power indices (e.g., HHI, 20% benchmark, residual supply index) is the clearest indicator of market concentration.

Figure 4.1.6-3 shows the company annual generation normalized to the installed capacity; that is, the annual generation was computed as a fraction of the total possible generation if all the company's units were operated at full capacity. Note that the annual generation includes time when units are out of service for planned, maintenance, and forced outages. Only the Exelon, Dynegy, and Ameren units were operated at high capacity factors in the PC case using Case Study Assumptions. Some other companies' units were operated in the range of 15-30% capacity factors while many of the others were at less than 10%. Company units that were operated at low capacity factors, or were not operated at all in the PC case, either were utilized only for peaking purpose for a limited number of hours, were not economically competitive in the market, or were located on the transmission grid where they could not be dispatched at a greater rate due to transmission limits.

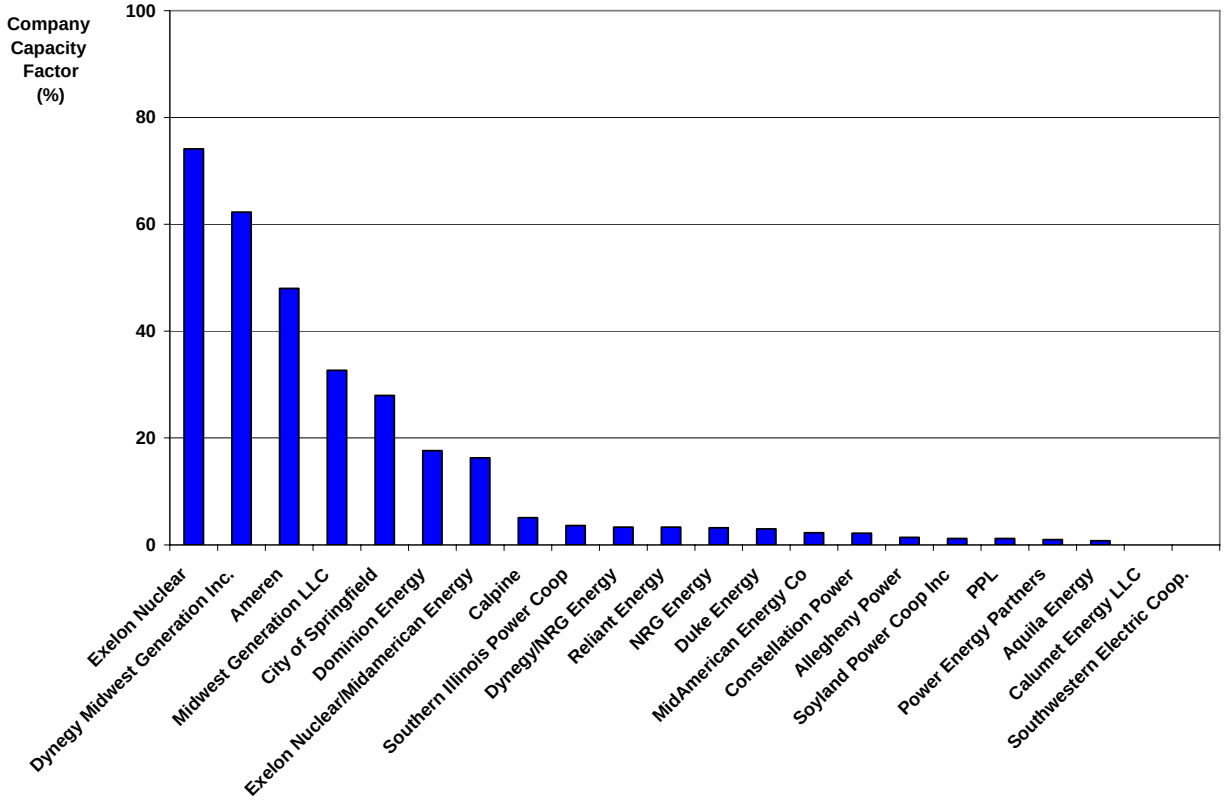


Figure 4.1.6-3 PC Case (Case Study Assumptions) Generation Company Capacity Factors

Figure 4.1.6-4 shows the operating revenues and costs for each of the GenCos. Table 4.1.6-2 shows the annual operating profit margin. Note that this profit margin is not a complete financial accounting of each company. Revenues are only from the sale of electricity and do not consider other revenue streams such as fees for engineering services provided to other companies; sales of equipment, facilities, or real estate; or returns on other company investments. Costs include only production costs. The cost of amortizing capital investments is not included here. Therefore, the profit margins shown in the table must be viewed as strictly based on generator operating parameters. Table 4.1.6-3 shows the company annual average revenue and cost rates per MWh generated. These rates were calculated based on the total generation that each company provided in the PC case. The very large values of cost rates and large negative values of operating profit rates result from the very small amount of generation that each of these companies provided in the PC case.

Table 4.1.6-4 shows the cost by type of unit. The nuclear and coal units were significantly cheaper by the production cost measure, with or without the inclusion of the fixed operating and maintenance costs. The natural gas units had high production costs per MWh generated, since their capacity factors were low and their fixed operation and maintenance costs were spread over a smaller level of generation.

Under PC case conditions, the companies with significant market share showed an operating profit, some very substantial. All of the others showed operating losses. For some of the companies showing losses, their generators were not being dispatched under PC case market conditions. Their generators were too expensive to compete effectively, even when all companies were bidding only production costs into the electricity market. For other companies, even if their generators were being dispatched, their utilization rates were too low for them to recover their fixed operating costs. In either case, this is not a sustainable position for these companies over an extended period of time. It can be noted that many of the companies that were identified as planning the construction of new generating capacity do not show operating profitability in the PC case.

If the amortization of capital costs were included in the cost figures, the profit margins would be different for each company. Those with large margins might not, in fact, have seen these large profits when capital cost amortization was included. Those with smaller margins might actually have been unprofitable. Those that already were experiencing negative margins would have been in an even weaker situation. Data on capital amortization and other debt service requirements of the GenCos were not available for this study.

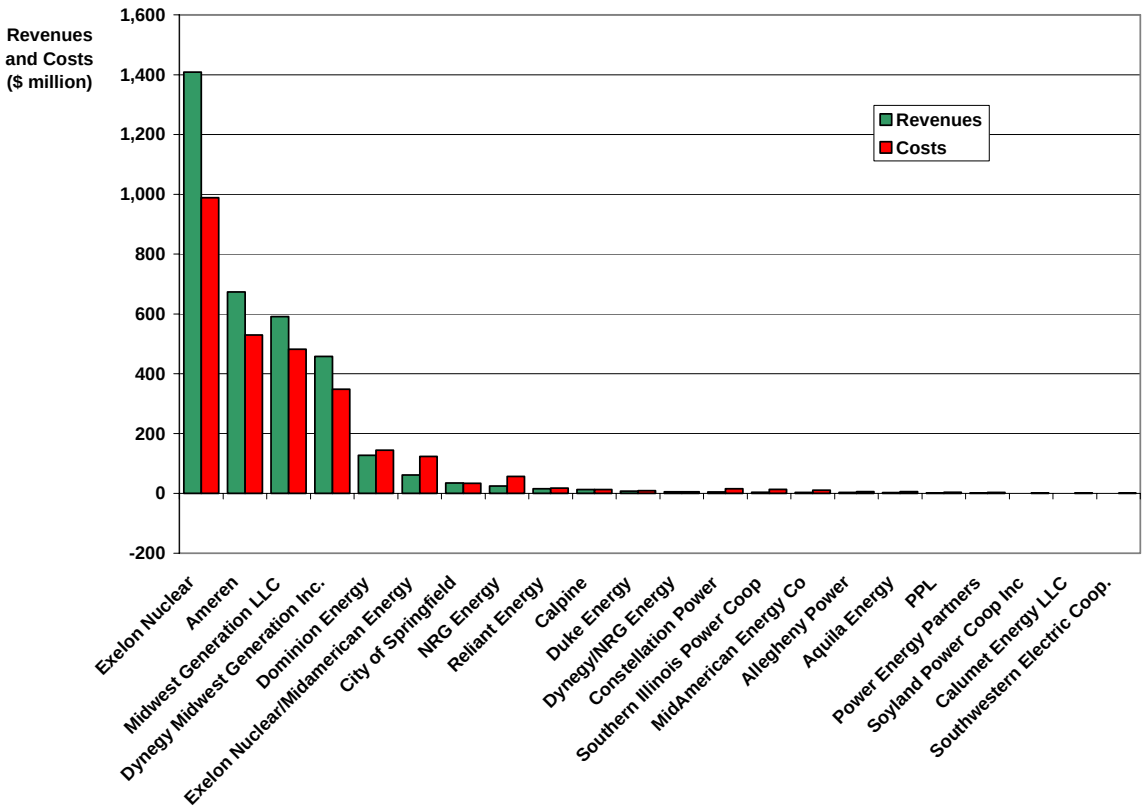


Figure 4.1.6-4 PC Case (Case Study Assumptions) Generation Company Revenues and Costs

Table 4.1.6-2 PC Case (Case Study Assumptions) Generation Company Revenues, Costs, and Operating Profitability

Generation Company	Revenues ($ Million)	Costs ($ Million)	Operating Profit Margin [a]
GenCo – Exelon Nuclear	1,408.6	988.5	42.5%
GenCo – Ameren	673.9	529.3	27.3%
GenCo – Midwest Generation LLC	591.1	482.0	22.6%
GenCo – Dynegy Midwest Generation Inc.	458.4	348.1	31.7%
GenCo – Dominion Energy	127.6	144.1	-11.4%
GenCo – Exelon Nuclear/Midamerican Energy	61.4	124.2	-50.5%
GenCo – City of Springfield	34.7	33.7	3.0%
GenCo – NRG Energy	24.7	56.3	-56.2%
GenCo – Reliant Energy	15.6	18.1	-13.6%
GenCo – Calpine	12.5	13.0	-3.7%
GenCo – Duke Energy	7.4	9.0	-18.3%
GenCo – Dynegy/NRG Energy	5.4	5.7	-4.5%
GenCo – Constellation Power	4.9	15.5	-68.3%
GenCo – Southern Illinois Power Coop.	4.0	13.3	-69.9%
GenCo – MidAmerican Energy Co.	3.3	10.4	-67.9%
GenCo – Allegheny Power	3.1	6.3	-50.1%
GenCo – Aquila Energy	2.2	6.2	-65.4%
GenCo – PPL	1.7	4.1	-57.3%
GenCo – Power Energy Partners	1.1	3.0	-61.7%
GenCo – Soyland Power Coop Inc.	0.7	1.6	-59.7%
GenCo – Calumet Energy LLC	0.0	1.8	-99.8%
GenCo – Southwestern Electric Coop.	0.0	1.1	-100.0%
Total	**3,442.4**	**2,815.2**	**22.3%**

[a] Revenues are from only the sale of electricity. Costs include only fuel, fixed and variable operation and maintenance costs, and startup/shutdown costs. The operating profit shown here is not a complete financial compilation.

Table 4.1.6-3 PC Case (Case Study Assumptions) Generation Company Revenue and Cost Rates

	Company Annual Average Based on PC Case Generation		
Generation Company	**PC Case Revenue Rate[a] ($/MWh Generated)**	**PC Case Cost Rate[b] ($/MWh Generated)**	**PC Case Operating Profit Rate ($/MWh Generated)**
Exelon Nuclear	21.2	14.9	6.3
Ameren	21.0	16.5	4.5
Midwest Generation LLC	22.1	18.1	4.1
Dynegy Midwest Generation Inc.	20.5	15.5	4.9
Dominion Energy	23.8	26.8	-3.1
Exelon Nuclear/Midamerican Energy	26.0	52.6	-26.6
City of Springfield	21.9	21.3	0.6
NRG Energy	33.3	76.0	-42.7
Reliant Energy	41.3	47.8	-6.5
Calpine	43.1	44.8	-1.7
Duke Energy	42.6	52.1	-9.5
Dynegy/NRG Energy	46.7	48.9	-2.2
Constellation Power	25.8	81.5	-55.7
Southern Illinois Power Coop.	29.1	96.6	-67.5
MidAmerican Energy Co.	29.8	92.7	-62.9
Allegheny Power	38.9	78.0	-39.1
Aquila Energy	42.0	121.2	-79.2
PPL	37.3	87.4	-50.0
Power Energy Partners	37.5	98.1	-60.5
Soyland Power Coop Inc.	37.1	92.0	-54.9
Calumet Energy LLC	29.9	15,724.4	-15,694.5
Southwestern Electric Coop.	Not dispatched	Not dispatched	Not dispatched

[a]The revenue rate is calculated by dividing the total revenue received by the company by the total generation in the PC case.
[b] The cost rate is calculated by dividing the total costs of the company's units in the PC case (including fuel, variable and fixed operating and maintenance, and startup/shutdown costs) by the total generation in the PC case. Large values of the cost rate (and large negative values of the operating profit rate) are due to the small amount of generation in the PC case.

Table 4.1.6-4 PC Case (Case Study Assumptions) – Generation Cost by Unit Type

		Costs ($million)						
Type	**Generation (GWh)**	**Fuel**	**Variable O/M**	**Fixed O/M**	**Startup/ Shutdown**	**Total Cost**	**Effective Operating Cost [a] ($/MWh)**	**Effective Production Cost [b] ($/MWh)**
Nuclear	68,675	327.9	380.8	381.2	21.0	1,110.8	10.3	16.2
Coal	87,243	1,012.7	159.7	246.4	58.0	1,476.9	13.4	16.9
Natural Gas	2,986	80.3	0.7	135.8	5.6	222.4	27.1	74.5
Oil	6	0.5	0.0	5.0	0.0	5.4	79.5	945.1
Hydro	244	-	-	-	-	-	-	-
Total	**159,154**	**1,421.4**	**541.2**	**768.4**	**84.6**	**2,815.6**		

[a] Based on fuel and variable O/M only.
[b] Based on total cost.

Generation Companies – Conservative Assumptions

Figure 4.1.6-5 shows the GenCo market share using the Conservative Assumptions. Exelon Nuclear's share of the in-state generation market increased to more than 60% while the shares of the other companies decreased proportionally. Recall that under the Conservative Assumptions, the State became a net importer of electricity as out-of-state companies were more competitive. Under these assumptions, Exelon Nuclear was able to maintain a competitive position while the other companies lost market share to out-of-state suppliers. This is the result of the fuel cost advantage of the nuclear units. Under the Conservative Assumptions, the production cost (excluding FOM) dropped considerably for the nuclear units and less so for the coal units. The natural gas units, whose production cost also dropped substantially under Conservative Assumptions, were still more than twice as expensive as the in-state nuclear and coal units. Under the Conservative Assumptions, the HHI based on generation increased to 3,797 (from 2,636 using the Case Study Assumptions), thus indicating an increase in market concentration for the in-state companies.

Figure 4.1.6-6 shows the operating revenues and costs of each of the in-state GenCos under Conservative Assumptions. Table 4.1.6-5 shows the annual operating profit margin under these conditions. With the exception of Exelon Nuclear, all companies were not profitable. Exelon Nuclear's operating profits dropped considerably. These changes came from the loss of market share to out-of-state suppliers and the lower market prices resulting from the exclusion of FOM in the production cost.

It is interesting to note that while the use of the Conservative Assumptions made more generation capacity available and would be expected to increase competition among suppliers, in fact the opposite was seen. Market concentration among in-state suppliers actually increased as market share was lost to out-of-state suppliers. Further, the Conservative Assumptions led to an unsustainable financial position for all GenCos, as all except one were unprofitable. The one profit level was very small.

Demand Companies – Case Study Assumptions

Under PC case assumptions, all DemCos offered their consumers the same purchase terms: the market price of electricity plus a 10% markup. Hence, there was no incentive for consumers to switch to alternative suppliers, and all were supplied by the same DemCo they had prior to restructuring. Figure 4.1.6-7 shows the load that was served by each DemCo in the PC case. Figure 4.1.6-8 shows the market share of each DemCo based on annual load served in the State. With these results, the HHI was computed to be 5,417, which indicates a highly concentrated market for DemCos. Using the FERC 20% benchmark shows that, as a demand company, Commonwealth Edison exceeded the benchmark level. The Ameren companies were at about 15%. Overall, three companies account for more than 98% of electricity sales to consumers. Recall that in the PC case assumptions, all the DemCos' load was considered to be firm load and not price-sensitive. Further, under the provisions of a fully restructured market, any DemCo licensed to operate in the State will be able to sell electricity to any consumer in the State.

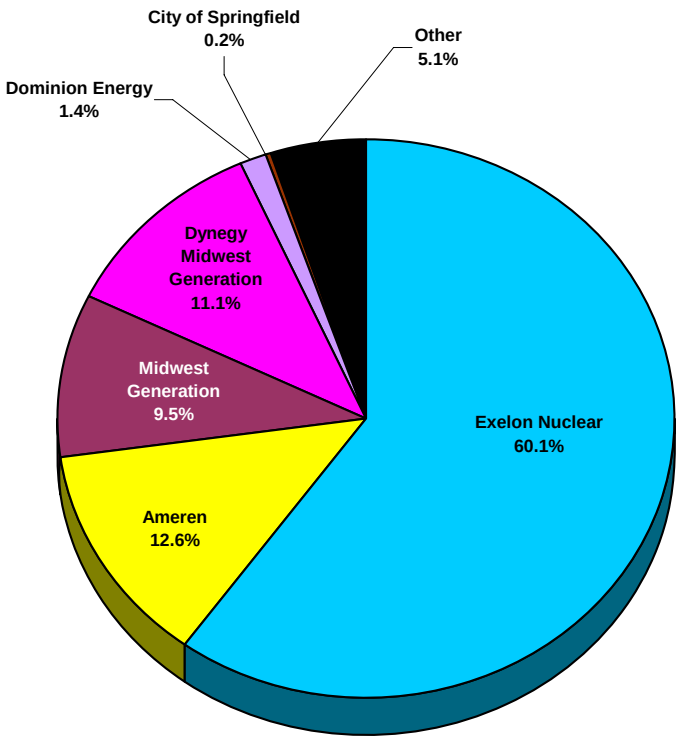


Figure 4.1.6.-5 PC Case (Conservative Assumptions) GenCo Market Share of Annual GWh of Generation

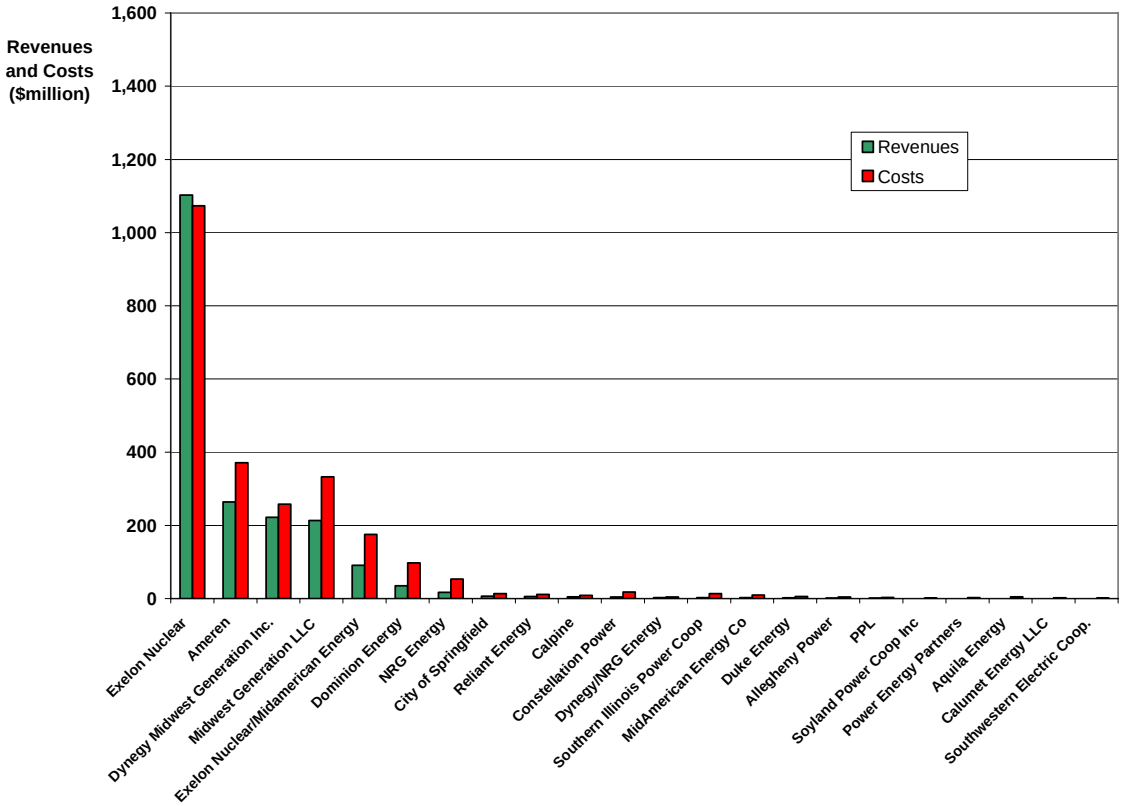


Figure 4.1.6-6 PC Case (Conservative Assumptions) Generation Company Revenues and Costs

Table 4.1.6-5 PC Case (Conservative Assumptions) Generation Company Revenues, Costs, and Operating Profitability

Generation Company	Revenues ($ Million)	Costs ($ Million)	Operating Profit Margin [a]
GenCo – Exelon Nuclear	1,102.7	1,073.5	2.7%
GenCo – Ameren	263.7	370.9	-28.9%
GenCo – Dynegy Midwest Generation Inc.	222.0	258.1	-14.0%
GenCo – Midwest Generation LLC	212.8	332.4	-36.0%
GenCo – Exelon Nuclear/Midamerican Energy	91.0	175.3	-48.1%
GenCo – Dominion Energy	34.4	97.5	-64.7%
GenCo – NRG Energy	16.8	53.5	-68.7%
GenCo – City of Springfield	6.4	13.1	-50.8%
GenCo – Reliant Energy	5.6	11.6	-52.2%
GenCo – Calpine	5.0	8.6	-41.3%
GenCo – Constellation Power	4.4	18.2	-75.6%
GenCo – Dynegy/NRG Energy	2.3	4.0	-41.8%
GenCo – Southern Illinois Power Coop.	2.2	13.0	-82.8%
GenCo – MidAmerican Energy Co.	2.2	9.9	-77.9%
GenCo – Duke Energy	1.6	5.3	-69.5%
GenCo – Allegheny Power	0.5	4.4	-88.2%
GenCo – PPL	0.3	3.0	-88.4%
GenCo – Soyland Power Coop Inc.	0.3	1.5	-81.3%
GenCo – Power Energy Partners	0.1	2.2	-96.2%
GenCo – Aquila Energy	0.0	4.5	-99.4%
GenCo – Calumet Energy LLC	0.0	1.8	-100.0%
GenCo – Southwestern Electric Coop.	0.0	1.1	-100.0%
Total	**1,974.4**	**2,463.2**	**-19.8%**

[a] Revenues are from only the sale of electricity. Costs include only fuel, variable operation and maintenance costs, and startup/shutdown costs. The operating profit shown here is not a complete financial compilation.

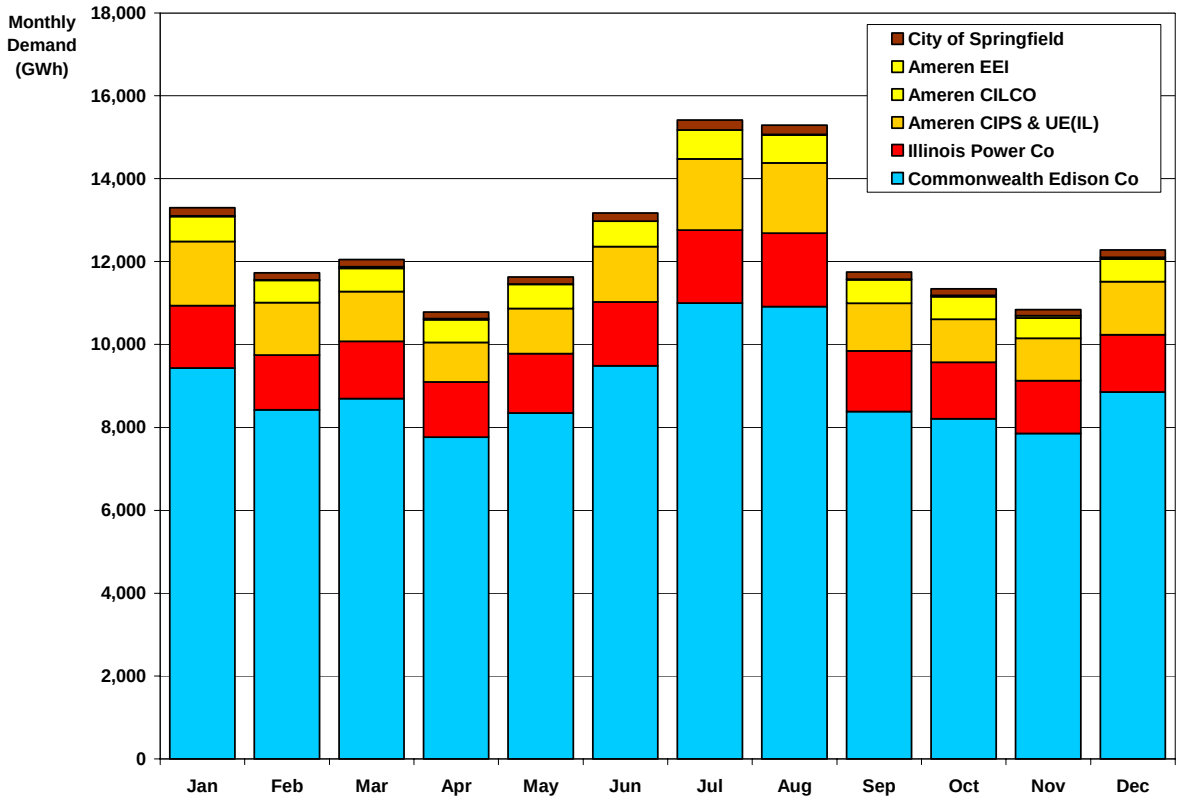


Figure 4.1.6-7 PC Case (Case Study Assumptions) Load Served by Demand Company

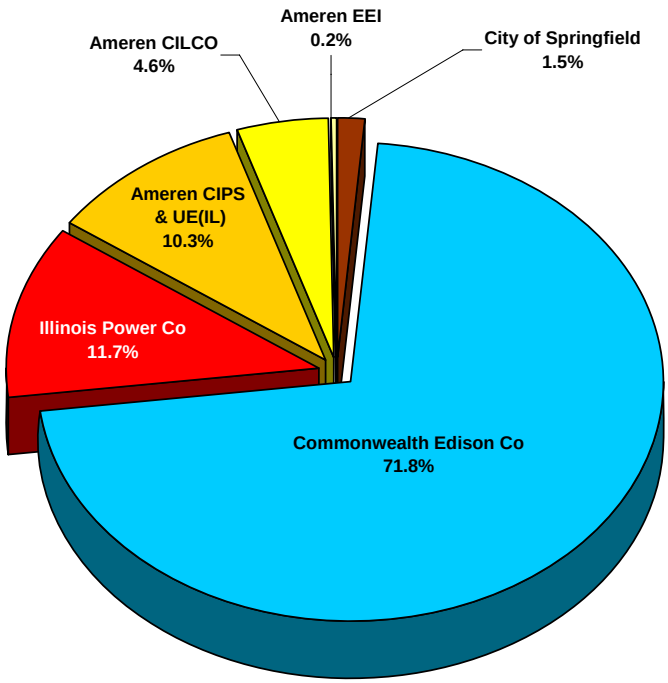


Figure 4.1.6-8 PC Case (Case Study Assumptions) Demand Company Market Share

Figure 4.1.6-9 shows the monthly revenues for the DemCos in the PC case. The revenues include payments received from consumers and payments for energy, transmission, and distribution services. By convention, the DemCos collected all of these from consumers and passed the transmission and distribution charges to the respective companies with no markup. A DemCo markup was applied only to the energy charges. Table 4.1.6-6 shows the annual revenues and costs. The costs include the pass-through payments made to TransCos and DistCos as well as the energy costs. Since there were no bilateral contracts in operation in the PC case, all of the energy costs arose from purchases from the pool energy market.

In the PC case, all of the DemCos are profitable by the assumption that they charged their consumers a markup of their cost of electricity purchases. As a point of comparison, in the recent electricity problems in California, the companies that are the equivalent of what is referred to here as a DemCo were not able to pass through their cost of electricity purchases to consumers because of tariff restrictions. This led to bankruptcy filings.

Demand Companies – Conservative Assumptions

Using the Conservative Assumptions, the load served and customer distribution among DemCos was unchanged from the Case Study Assumptions. The DemCo revenues and costs were reduced as a result of the reduction in energy charges, as shown in Table 4.1.6-7. The operating profit margin was reduced as a result of the reduction in energy costs, while transmission and distribution costs were unchanged.

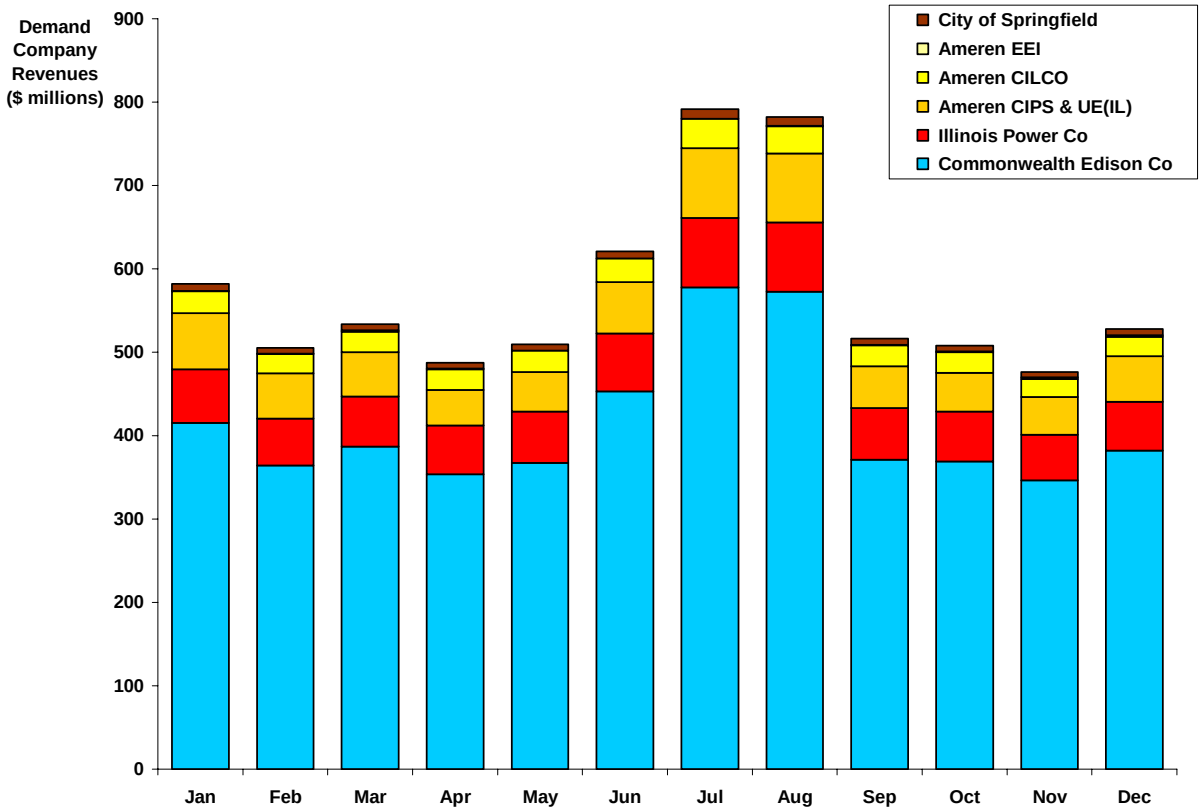


Figure 4.1.6-9 PC Case (Case Study Assumptions) Demand Company Revenues

Table 4.1.6-6 PC Case (Case Study Assumptions) Demand Company Annual Revenues and Costs

Demand Company	Revenues[a] ($Million)	Costs[b] ($ Million)	Operating Profit Margin (%)
DemCo Commonwealth Edison	4,959.3	4,715.1	5.2
DemCo Illinois Power	772.8	736.3	5.0
DemCo Ameren			
Ameren CIPS,UE(IL)	688.0	655.0	5.0
Ameren CILCO	315.0	299.8	5.1
Ameren EEI	10.4	10.0	5.0
DemCo City of Springfield	96.8	92.2	5.1
Total	**6,842.2**	**6,508.4**	**5.1**

[a] Revenues are payments received from consumers and include charges for energy, transmission, and distribution services. No markup is applied to the transmission and distribution charges by the DemCo.
[b] Costs include the pass through of the transmission and distribution payments received from consumers.

Table 4.1.6-7 PC Case (Conservative Assumptions) Demand Company Annual Revenues and Costs

Demand Company	Revenues[a] ($Million)	Costs[b] ($ Million)	Operating Profit Margin (%)
DemCo Commonwealth Edison	4,131.3	3,961.9	4.3
DemCo Illinois Power	657.9	631.7	4.1
DemCo Ameren			
Ameren CIPS,UE(IL)	581.1	557.7	4.2
Ameren CILCO	263.9	253.3	4.2
Ameren EEI	8.9	8.5	4.0
DemCo City of Springfield	82.3	79.0	4.2
Total	5,725.4	5,492.1	4.2

[a] Revenues are payments received from consumers and include charges for energy, transmission, and distribution services. No markup is applied to the transmission and distribution charges by the DemCo.
[b] Costs include the pass through of the transmission and distribution payments received from consumers.

Distribution Companies

Figure 4.1.6-10 shows the monthly revenue received by DistCos. Table 4.1.6-8 summarizes these results over the year. Recall that the DistCos charged a fixed rate of 18 $/MWh for the use of their facilities and did not engage in any strategic market behavior.

Applying the Conservative Assumptions did not change the distribution charges.

Transmission Company – Case Study Assumptions

Figure 4.1.6-11 shows the monthly revenues of the single TransCo assumed in the PC case. Table 4.1.6-9 summarizes the results over the year. The revenues include the transmission use charge (TUC), which is a fixed fee of 3 $/MWh, and the transmission congestion payment (TCP), which results from the difference in LMPs, as described previously. During lower load periods, the transmission use charge made up almost all the revenues, since there was little congestion during these periods. In January, the TCP was actually negative because of the directional convention used in computing it, as was described earlier. In a market where transmission rights were sold, this would imply a reimbursement by the holders of these rights to the transmission company. The transmission rights market was not included in this simulation. During high load periods the transmission congestion payment made up almost one-half of the revenue.

Transmission Company – Conservative Assumptions

Use of the Conservative Assumptions did not change the TUC but did reduce the TCP, due to the lower LMPs around the system. This is shown in Table 4.1.6-10.

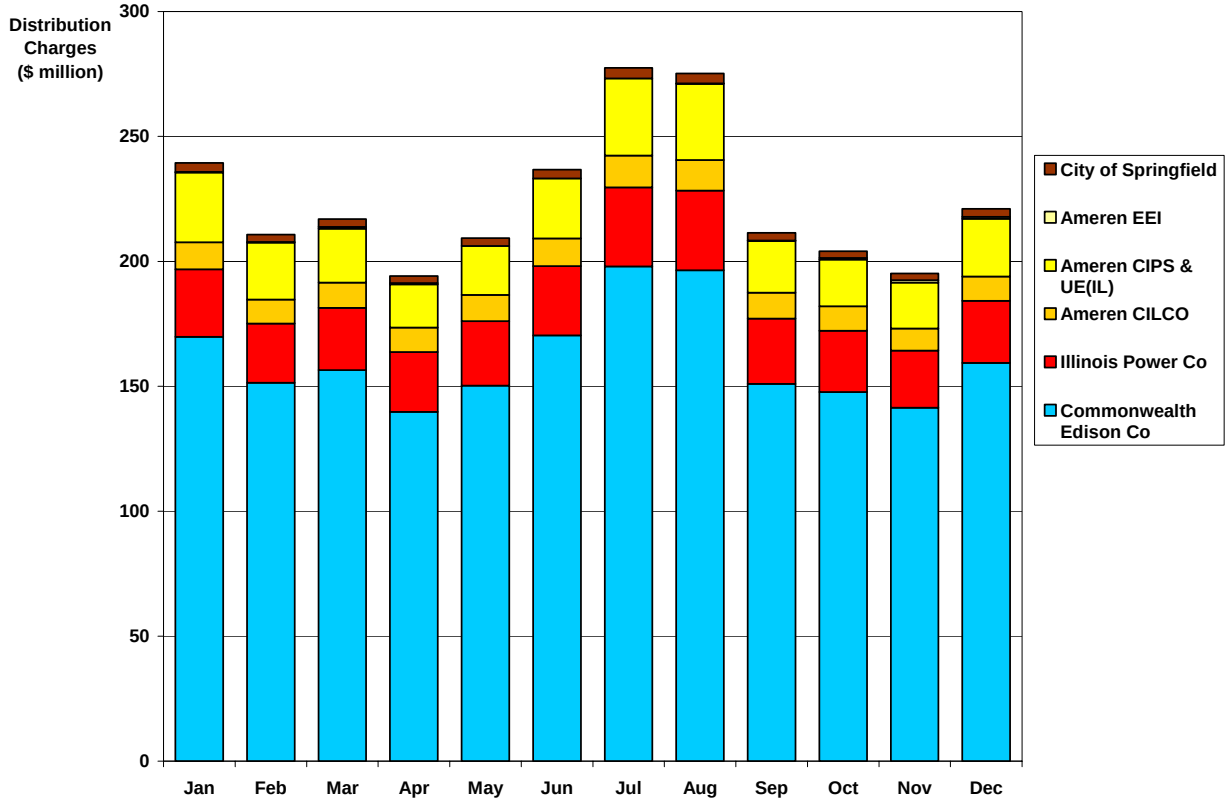


Figure 4.1.6-10 PC Case Distribution Company Revenues

Table 4.1.6-8 PC Case (Case Study and Conservative Assumptions) Distribution Company Annual Revenues

Distribution Company	Revenues ($Million)
DistCo – Commonwealth Edison Co.	1,931.9
DistCo – Illinois Power Co.	315.3
DistCo – Ameren - CIPS & UE(IL)	275.6
DistCo – Ameren - CILCO	125.5
DistCo – Ameren - EEI	4.4
DistCo – City of Springfield	39.2
Total	**2,691.7**

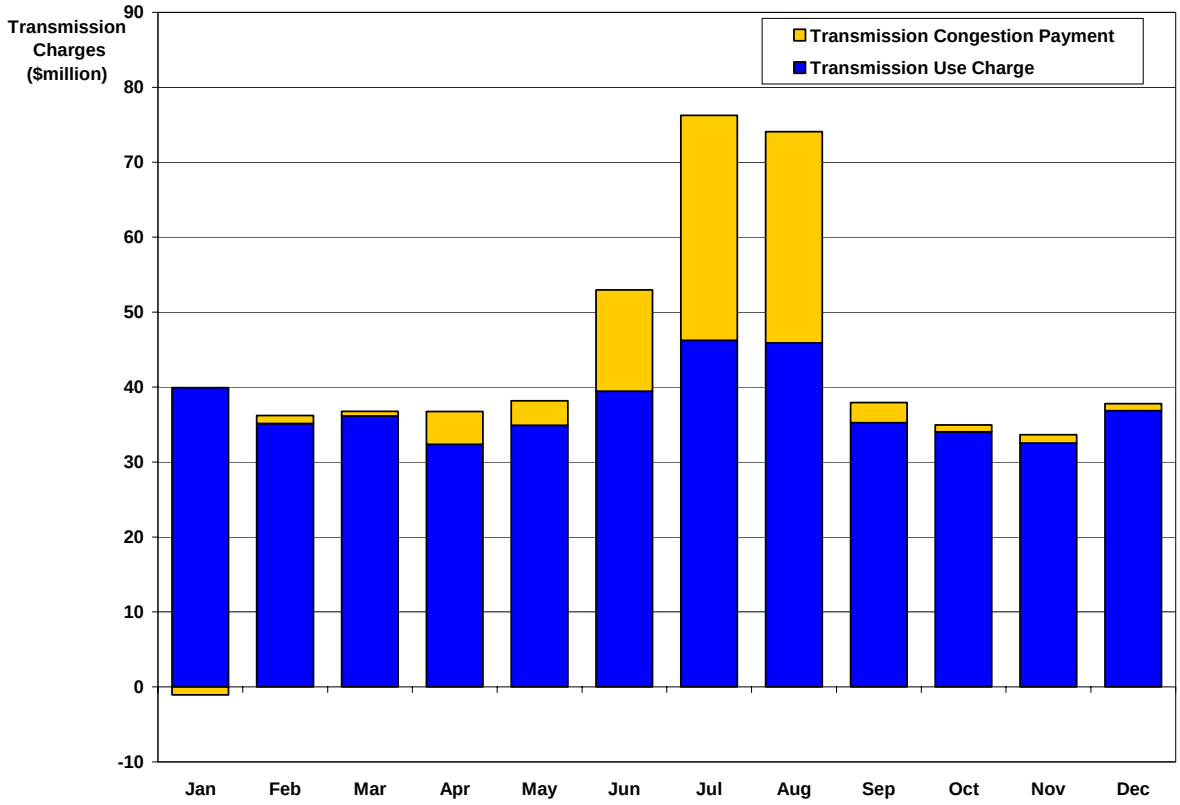


Figure 4.1.6-11 PC Case (Case Study Assumptions) Transmission Company Revenue

Table 4.1.6-9 PC Case (Case Study Assumptions) Transmission Company Annual Revenue

Transmission Company	Revenue ($Million)
TransCo Transmission Use Charge	448.6
TransCo Transmission Congestion Payment	85.7
TOTAL	**534.3**

Table 4.1.6-10 PC Case (Conservative Assumptions) Transmission Company Annual Revenue

Transmission Company	Revenue ($Million)
TransCo Transmission Use Charge	448.6
TransCo Transmission Congestion Payment	64.8
TOTAL	**513.4**

Consumers – Case Study Assumptions

Figure 4.1.6-12 shows the monthly costs paid by consumers for electricity in the PC case. The consumer costs include payments for energy, transmission services, and distribution services. Energy and distribution charges made up more than 90% of the costs. The transmission costs shown here are the TUCs. They made up a relatively small portion of the total. The transmission costs shown in the figure do not include the TCPs since, for consumers, these are reflected in the LMPs that are used to determine their energy costs and are, therefore, included in that part of the figure. Consumer costs were highest in the peak load months of June, July, and August, which together accounted for about 30% of the annual costs.

Figure 4.1.6-13 shows the distribution of consumer costs by zone. About 70% of the consumer costs were incurred in the NI zones, where the same portion of the State's load is concentrated.

Figure 4.1.6-14 shows the monthly variation in consumer price for electricity. The actual price varied by hour through the analysis year. Shown is the load-weighted average by zone for each month. The prices in the NI zones were consistently higher throughout the year than elsewhere in the State due to transmission limits. The IP, AMRN, and SIPC zones showed consistently lower consumer prices. For the CILC and CWLP zones, prices showed more volatility than elsewhere. These results derive from the variation in zonal LMPs due to transmission congestion, as was discussed in Section 4.1.4. Consumers paid the LMP of the zone they are located in, plus the transmission and distribution charges. Thus, the transmission limits can be seen to have a direct impact on consumer prices. Higher production costs resulted, since units must be redispacthed to relieve congestion. Congestion charges also added to consumer costs.

During the lower-load months, the prices were closer together throughout the State. During the peak months of June, July, and August the prices increased, as did their spread. There was about a 9% spread in prices in January. This increased to about 19% in August. These results also follow the variation in zonal LMPs discussed earlier.

Table 4.1.6-11 shows the annual consumer costs by zone along with the annual average electricity price. The variation in annual average electricity price across the State resulted in a 12% difference between the highest and lowest values under PC case conditions. This is a relatively modest variability given the wide range of loads across the State. The implication is that under PC case conditions, transmission congestion can create a spread in consumer costs in peak-load months (about 19% from Figure 4.1.6-14), but the annual average variation is smaller (5% from Table 4.1.6-11), since the energy portion of the consumer bill, which is most affected by the transmission congestion, is on the order of half the total.

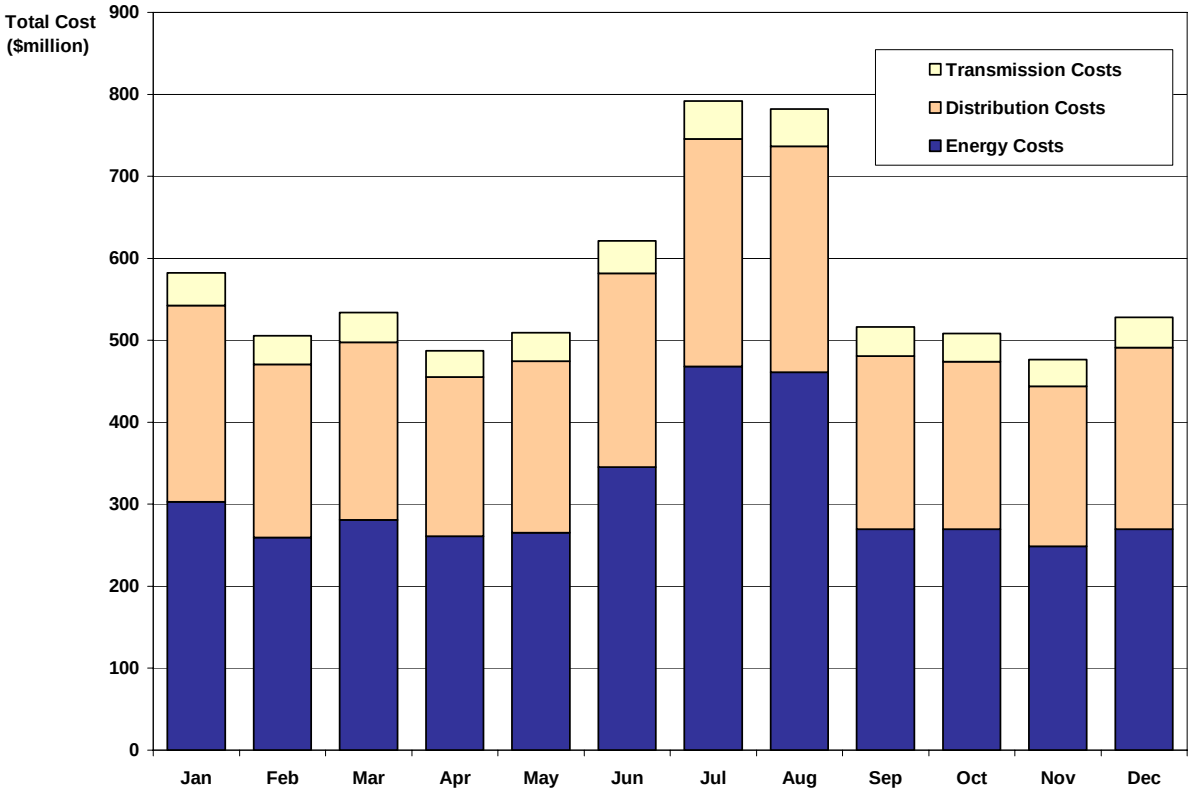


Figure 4.1.6-12 PC Case (Case Study Assumptions) Consumer Costs

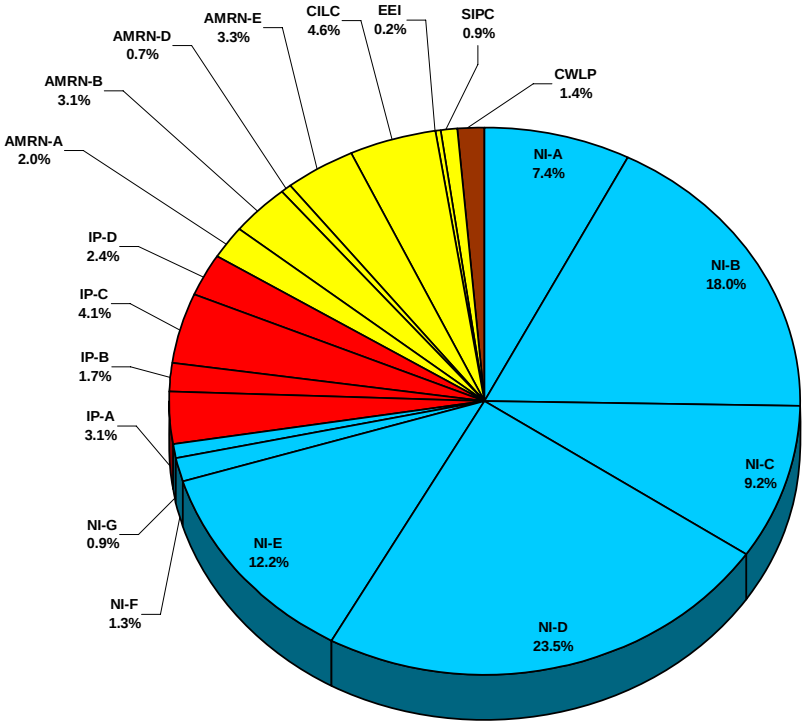


Figure 4.1.6-13 PC Case (Case Study Assumptions) Consumer Cost Distribution by Zone

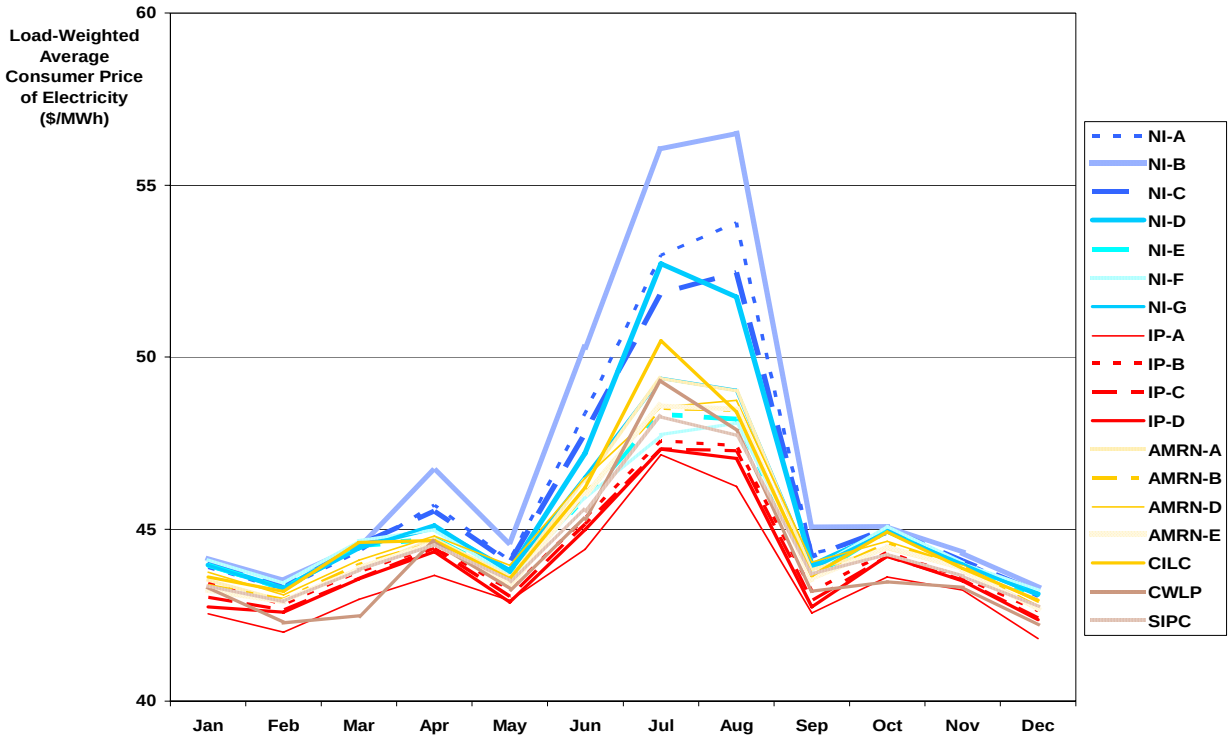


Figure 4.1.6-14 PC Case (Case Study Assumptions) Consumer Price of Electricity

Table 4.1.6-11 PC Case (Case Study Assumptions) Consumer Costs by Zone

Zone	Demand (TWh)	Energy Costs [a] ($million)	Transmission Use Charges [b] ($million)	Distribution Use Charges [c] ($million)	Total Consumer Cost ($million)	Average Cost of Electricity [d] ($/MWh)
NI-A	10.9	277.2	32.7	196.3	506.2	46.4
NI-B	25.9	685.8	77.8	466.7	1,230.3	47.4
NI-C	13.6	341.9	40.8	244.9	627.6	46.1
NI-D	35.0	874.0	104.9	629.4	1,608.3	46.0
NI-E	18.6	446.7	55.8	335.0	837.6	45.0
NI-F	2.0	48.1	6.0	36.1	90.2	45.0
NI-G	1.3	31.7	3.9	23.5	59.0	45.3
NI Total	**107.3**	**2,705.4**	**321.9**	**1,931.9**	**4,959.3**	**46.2**
IP-A	4.8	109.1	14.4	86.4	209.9	43.7
IP-B	2.7	63.0	8.1	48.3	119.4	44.5
IP-C	6.3	146.5	18.9	113.3	278.7	44.3
IP-D	3.7	86.4	11.2	67.2	164.8	44.2
IP Total	**17.5**	**405.0**	**52.5**	**315.3**	**772.8**	**44.2**
AMRN-A	3.0	71.5	8.9	53.3	133.7	45.1
AMRN-B	4.8	113.9	14.3	85.7	213.9	44.9
AMRN-D	1.1	26.7	3.3	19.9	49.9	45.2
AMRN-E	5.1	121.5	15.3	91.6	228.4	44.9
AMRN Total	**14.0**	**333.7**	**41.7**	**250.3**	**625.9**	**44.7**
CILC	7.0	168.6	20.9	125.5	315.0	45.2
EEI	0.2	5.4	0.7	4.4	10.4	43.1
SIPC	1.4	32.9	4.2	25.1	62.1	44.6
CWLP	2.2	51.1	6.5	39.2	96.8	44.5
Total	**149.5**	**3,702.0**	**448.6**	**2,691.7**	**6,842.3**	**45.8**

[a] Includes cost of energy purchased from DemCo serving the consumer. This cost includes DemCo markup on energy sales.
[b] Includes transmission use charge. By convention, this is paid by consumers to the DemCo, but there is no markup added. Transmission congestion charges are calculated on each line in the transmission network as the difference in LMPs. Therefore, consumers experience transmission congestion charges as part of their energy charge.
[c] Includes distribution use charges. By convention, this is paid by consumers to the DemCo, but there is no markup added.
[d] Demand-weighted average.

Consumers – Conservative Assumptions

Figure 4.1.6-15 shows the monthly consumer price for electricity under Conservative Assumptions. Table 4.1.6-12 shows the annual consumer costs by zone. During the low-load months, prices are very close across the State. During the peak-load months, the prices increase and spread apart as before. Overall, the consumer prices and costs are lower under the Conservative Assumptions, since more generation capacity is offered into the market at lower prices. Nevertheless, the effect of transmission congestion remains, as demonstrated by the spread in prices during the peak load months. The degree of spread during these months is only slightly smaller than under the Case Study Assumptions (17% instead of 20%). On an annual basis, the degree of spread is essentially unchanged from the Case Study Assumptions.

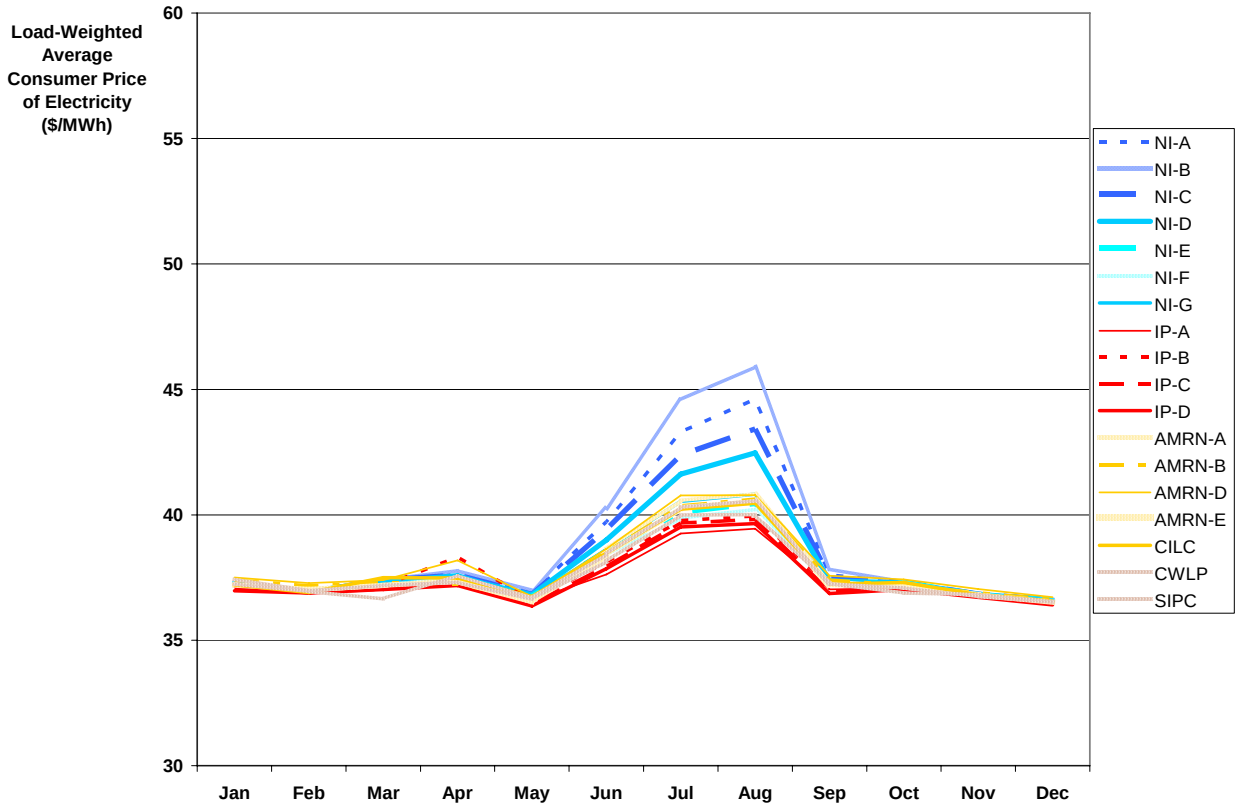


Figure 4.1.6-15 PC Case (Conservative Assumptions) Consumer Price of Electricity

Table 4.1.6-12 PC Case (Conservative Assumptions) Consumer Costs by Zone

Zone	Demand (TWh)	Energy Costs [a] ($million)	Transmission Use Charges [b] ($million)	Distribution Use Charges [c] ($million)	Total Consumer Cost ($million)	Average Cost of Electricity [d] ($/MWh)
NI-A	10.9	194.1	32.7	196.3	423.1	38.8
NI-B	25.9	470.1	77.8	466.7	1014.6	39.2
NI-C	13.6	238.4	40.8	244.9	524.1	38.5
NI-D	35.0	604.4	104.9	629.4	1338.7	38.2
NI-E	18.6	313.9	55.8	335.0	704.7	37.9
NI-F	2.0	33.7	6.0	36.1	75.8	37.9
NI-G	1.3	22.1	3.9	23.5	49.5	38.1
NI Total	**107.3**	**1,876.7**	**321.9**	**1,931.9**	**4,130.5**	**38.5**
IP-A	4.8	79.2	14.4	86.4	180	37.5
IP-B	2.7	45.0	8.1	48.3	101.4	37.6
IP-C	6.3	104.3	18.9	113.3	236.5	37.5
IP-D	3.7	61.5	11.2	67.2	139.9	37.8
IP Total	**17.5**	**290.0**	**52.5**	**315.3**	**657.8**	**37.6**
AMRN-A	3.0	50.3	8.9	53.3	112.5	37.5
AMRN-B	4.8	80.9	14.3	85.7	180.9	37.7
AMRN-D	1.1	19.0	3.3	19.9	42.2	38.4
AMRN-E	5.1	85.9	15.3	91.6	192.8	37.8
AMRN Total	**14.0**	**236.2**	**41.7**	**250.3**	**528.2**	**37.7**
CILC	7.0	117.5	20.9	125.5	263.9	37.7
EEI	0.2	3.8	0.7	4.4	8.9	37.1
SIPC	1.4	23.3	4.2	25.1	52.6	37.6
CWLP	2.2	36.6	6.5	39.2	82.3	37.4
TOTAL	**149.5**	**2,584.1**	**448.6**	**2,691.7**	**5,724.4**	**38.3**

[a] Includes cost of energy purchased from DemCo serving the consumer. This cost includes DemCo markup on energy sales.
[b] Includes transmission use charge. By convention, this is paid by consumers to the DemCo, but there is no markup added. Transmission congestion charges are calculated on each line in the transmission network as the difference in LMPs. Therefore, consumers experience transmission congestion charges as part of their energy charge.
[c] Includes distribution use charges. By convention, this is paid by consumers to the DemCo, but there is no markup added.
[d] Demand-weighted average.

Agent Summary – Case Study Assumptions

Figure 4.1.6-16 summarizes the PC case revenue and cost flows. It should be emphasized that these flows represent operational considerations only and do not include items such as amortization of capital investments, taxes, fees, and other such financial parameters. As such, this is not intended to represent a complete financial accounting of the electricity system in the State.

Consumers ultimately paid for all the services received from the power system. By convention here, it was assumed here that consumer payments were all sent to the demand companies that were their suppliers. In the PC case, there were no bilateral contracts; hence demand companies purchased all of their electricity from the day-ahead pool market, which was administered by the independent system operator (ISO). Also by convention here, the ISO handled the settlement payments to all market participants. Generation companies received payment for the energy sold into the day-ahead market. The single transmission company received transmission use charges, which were based on a fixed charge rate per MWh, and transmission congestion charges, which were calculated based on the differences in LMPs. Distribution companies received distribution service charges, which were based on a fixed charge rate per MWh. Generation companies, the single transmission company, and the

distribution companies all had costs associated with the operation of their equipment. Only the generation costs (i.e., fuel, operating and maintenance) were estimated here.

The results show that under PC case conditions, consumers in the State would pay $6.84 billion for electricity in the analysis year. The cost of electricity generation was the largest component of consumer costs at $3.44 billion per year. Distribution costs were the next largest at $2.69 billion per year. Since the distribution system is the most equipment- and labor-intensive part of any electric power system, it is not surprising that these costs made up such a large portion of the total cost. Transmission use costs were a much smaller portion of the total at $0.45 billion. In the PC case, transmission congestion charges added $0.09 billion or about 1.3% to the total cost and were less than the transmission use charges.

Out-of-state purchases and sales of electricity netted out to $0.16 billion inflow to State companies over the year. These are wholesale energy costs, since the out-of-state analysis did not include transmission and distribution charges.

Also shown on the figure are the annual average electricity prices. Consumers across the State paid an average of 45.8 $/MWh (4.58 ¢/kWh). GenCos earned 3.91 $/MWh in operating profit, which included profits from out-of-state sales. DemCos earned 2.30 $/MWh.

Agent Summary – Conservative Assumptions

Figure 4.1.6-17 shows the revenue and cost flows under Conservative Assumptions. In general, the revenues and costs decreased with the lower generation costs. The most significant changes are that the GenCos had a negative operating profit over the year, and the net from wholesale out-of-state purchases and sales shows the result of the State being a net importer of electricity under these conditions.

Comparison with Historical Data

Table 4.1.6-13 shows a comparison of some of the PC case results to historical data for the year 2002. These results are comparable only in the broadest of terms for several reasons. First, as was described earlier, the cost accounting included here represents only operating expenses and revenues. Under PC case conditions, companies used only production costs (i.e., fuel and operating and maintenance costs) to formulate their bids into the electricity market. Cost components such as capital amortization, fees, taxes, and other such items were not included. In current practice, these items are factored into the rate base and result in higher prices. A more detailed cost accounting, which was not possible here, would likely bring the prices in the simulation closer to historical patterns. Second, the electricity market that is represented in the PC case is significantly different than what is currently in place. In the PC case, all companies compete in the day-ahead pool market to provide electricity to any point in the State, subject to the limitations of the transmission system. This has the effect of making more capacity available throughout the State, thus lowering prices.

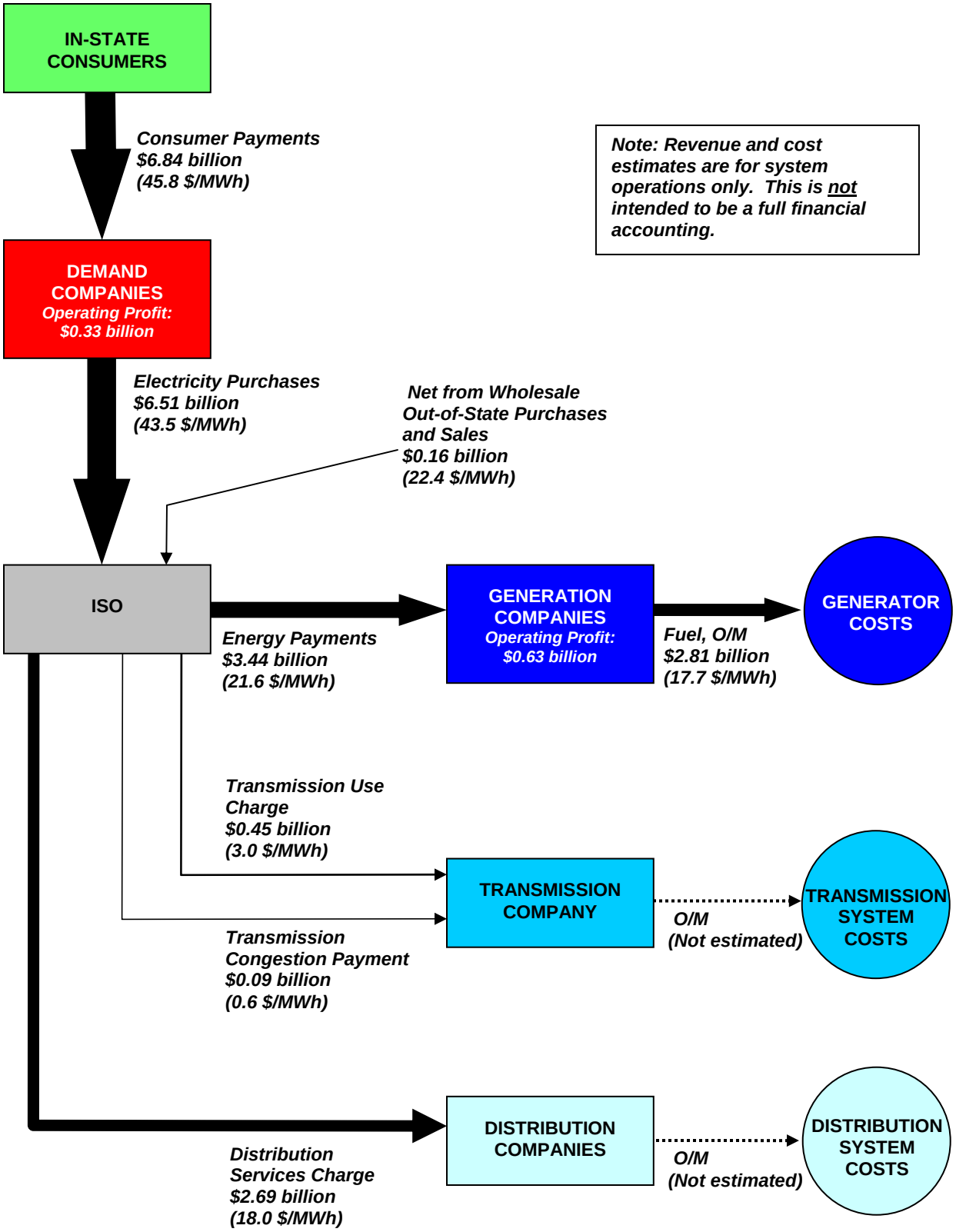


Figure 4.1.6-16 PC Case (Case Study Assumptions) Revenue and Cost Flow

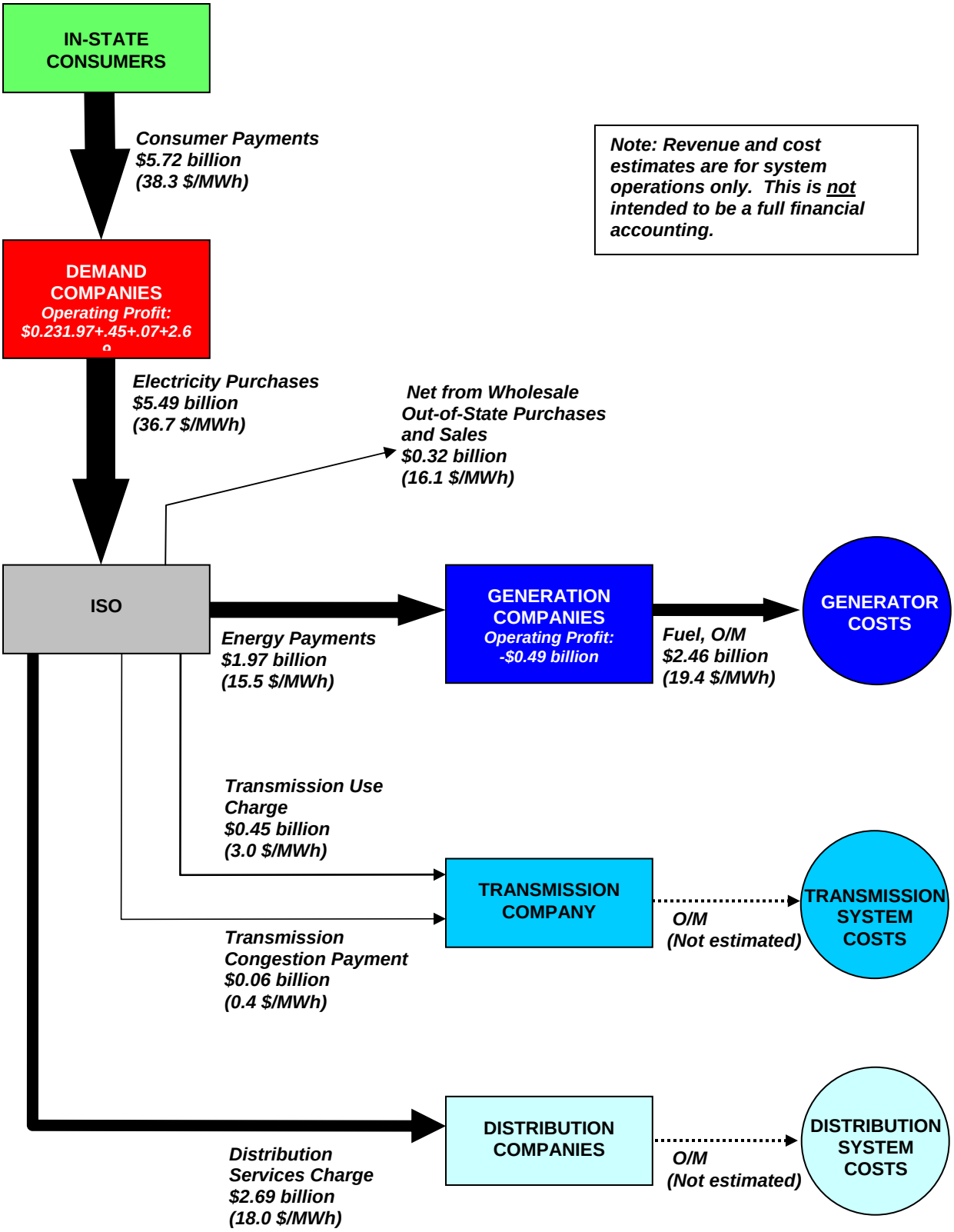


Figure 4.1.6-17 PC Case (Conservative Assumptions) Revenue and Cost Flow