Table 4.1.6-13 Comparison of 2002 Historical Data with PC Case Results

		PC Case Analysis Year Approximately Comparable Result	
	2002 Historical Data [a]	Case Study Assumptions	Conservative Assumptions
Sales of Electricity to Ultimate Customers	127.3 TWh	149.6 TWh	149.6 TWh
Revenues from Sales of Electricity to Ultimate Customers	$8.07 billion	$6.84 billion	$5.72 billion
Revenue Rate from Sales of Electricity to Ultimate Customers	6.34 ¢/kWh	4.58 ¢/kWh	3.83 ¢/kWh

[a] Source: Illinois Commerce Commission

4.1.7 Production Cost Case Summary

The following summary observations can be made from the PC case results:

- The PC case results showed a concentration of market share for both GenCos and DemCos and the existence of transmission congestion during high-load periods, even when none of companies was engaging in strategic market behavior to increase profits. This is an indication that the potential for market power exists. The use of the Conservative Assumptions, which resulted in more generation capacity being available, did not change this situation. In fact, the concentration in the in-state generation market increased under these assumptions as out-of-state suppliers gained a higher market share at the expense of some of the in-state suppliers.

- Under PC case conditions, across most of the State there was adequate generation capacity available and relatively little transmission congestion during low-load periods. With some exceptions, the LMPs in each zone were close to each other and varied by a relatively small amount as the load increased and decreased. In the high-load periods, all areas of the State experienced an increase in the magnitude of electricity prices. The magnitude of the increase was due to the need to bring more expensive generators on-line to serve the load. In the high-load periods, some areas of the State showed evidence of transmission congestion. Not only did the magnitude of the LMPs increase, but the variation from each other increased significantly. It is the difference in LMPs between zones that is the indicator of transmission limitations. Application of the Conservative Assumptions reduced the magnitude of the price increase, and the spread of price increases across the State, since more capacity was made available at lower bid prices. However, the effect of transmission congestion was still noticeable. Prices in the northern part of the State were more than double those elsewhere due to this congestion.

- Under PC case conditions, the cost of electricity to consumers was about $6.84 billion per year. Of that, approximately $0.33 billion went as operating profit to demand companies that served as electricity suppliers; $3.44 billion to generation companies, which spent about $2.81 billion operating their equipment; $2.69 billion to distribution companies; and $0.54 billion to the transmission company. Transmission congestion accounted for about 1.3% of the total costs on an annual basis. About $0.16 billion was received from electricity sales to out-of-state consumers. (The actual cost of electricity to consumers in 2002 was $8.07 billion. This is not directly comparable to PC case results since the analysis done here did not account for all of the costs incurred by companies that would likely be passed on to consumers.) Use of the Conservative Assumptions generally lowered all these values. The most significant impact of these assumptions was that the sum of the operating profits of the in-state GenCos became negative (-$0.49 billion instead of +$0.63 billion) and the net of out-of-state purchases and sales was negative, as the State was a net importer of electricity under these assumptions.

- The prices that consumers paid for electricity under competitive market conditions in the PC case varied by region and time. The annual average price of electricity across the State was 4.58 ¢/kWh. Payments for energy, transmission, distribution, and demand company services amounted to 2.2 ¢/kWh, 0.4 ¢/kWh, 1.8 ¢/kWh, and 0.2 ¢/kWh, respectively. For much of the year, the prices throughout the State were close. During peak-load months, the rates in some parts of the State were as much as 19% higher. On an annual average basis, the variation across the State was about 5%. Use of the Conservative Assumptions lowered the annual average price paid by consumers to 3.83 ¢/kWh. The variation across the State remained essentially the same.

- Under PC case market conditions, Illinois exported a portion of its electricity throughout the year. On an annual basis, the net export amounted to about 6% of the total generation. State installed capacity was in excess of the peak demand, and the exports can be attributed to the economic competitiveness of power generated in the State. Under Conservative Assumptions, the State is a net importer of electricity (approximately 15%). The dropping of the forced outages, company-level unit commitment, and fixed operating and maintenance costs from both the in-state and out-of-state suppliers resulted in the out-of-state suppliers being more economically competitive. They gained market share under these conditions.

- Virtually all of the in-state generation was provided by nuclear and coal units. On an annual basis, only about 2% of the generation in the State was from natural gas or other fuels under PC case conditions. This was true despite the recent large capacity additions of gas-fired units and the relatively low natural gas prices assumed for the PC case. Use of the Conservative Assumptions did not alter this.

- On an annual basis, the effects of transmission congestion were seen in the northern part of the State with the highest potential in the Chicago metropolitan area. The area north of Chicago and west to the Iowa border also saw significant impacts. Additional

impacts were seen in a broad area stretching southwest of Chicago to Peoria and south to Springfield. Smaller pockets of high LMPs were seen in the Sidney, Crossville, Joppa, and Pinckneyville areas. Under Conservative Assumptions, a similar pattern was observed, but was less pronounced.

- Under PC case conditions, including the assumptions about fuel prices, forced outages, and production cost bidding, the generation market was highly concentrated with five generation companies together accounting for 98% of the generation sales. The use of the Conservative Assumptions concentrated this even further, since some of the in-state suppliers could not compete well with out-of-state suppliers under these conditions. One company, Exelon Nuclear, accounted for more than 60% of the generation under these conditions.

- With generation companies bidding into the market at production costs, not all showed an operating profit over the year. The electricity prices on this basis were not high enough to allow all companies to recover their fixed operating costs. Including capital amortization would have exacerbated this situation. Of the 24 companies that own generators in the State, only five showed an operating profit in the PC case. Four of the six are large companies that are currently major participants in the electric power system in the State. Under Conservative Assumptions, all companies except one did not show any operating profit. The one company that did show an operating profit, Exelon Nuclear, had only a very small return. The lower market prices that resulted from these assumptions made it impossible for companies to recover fixed costs. The sustainability of this situation would worsen if capital expenditures were factored into the analysis.

- Under PC case assumptions, in which there was no switching by consumers from one demand company to an alternative supplier, the sale of electricity to consumers was highly concentrated, with three demand companies accounting for more than 98% of sales. The same was true under Conservative Assumptions.

Overall, the PC Case results, under both Case Study and Conservative Assumptions, demonstrated the potential for market power, as defined earlier, to be exerted. Transmission congestion was evident, and there was a concentration in the generation market. The extent to which this market power could be exerted was evaluated in the additional cases that are reported in the following sections.

4.2 PHYSICAL WITHHOLDING CASES

Generation companies participating in a competitive electricity market may elect to take capacity off-line in order to improve their business position. There are two basic conditions under which this physical withholding can be profitable for a generation company:

- *Low prices inhibit cost recovery.* In this situation, a company may determine that the expected market price is too low to operate a unit (or units) profitably. Under these circumstances, the market price may be so low that it is not possible to recover the cost of fuel to run the unit. A generation company can decide that it is cheaper not to run the unit and to wait until prices rise to a level that would allow at least the recovery of fuel and other operating costs.

- *Withholding capacity increases profitability of other units.* In this situation, a company with a portfolio of generators may decide to take one or more units off-line in an effort to cause the LMPs around the system to increase, thus increasing the profit on all its other operating units.

Withholding capacity during periods of low prices is a routine situation and may not indicate an attempt to exercise market power. In fact, all generation companies practice this by shutting down their most expensive-to-operate units during low-load conditions. In the PC case under Case Study Assumptions, the EMCAS model employs a company-level unit commitment algorithm (i.e., the CLUCRA algorithm discussed earlier) that simulates this decision-making in the day-ahead market. That is, generation companies project the day-ahead market prices and take units off-line that are not expected to be able to operate at a profit. Hence, withholding capacity can occur even when such action has no material impact on prices, but is merely a response to the expectation of low prices in the market. (Under the Conservative Assumptions, this CLUCRA algorithm is not used.)

There are many ways for a GenCo to implement a physical withholding strategy with the intent of exercising market power. To identify what approaches might yield attractive results, several tests were done with the EMCAS model. Simulations were carried out in which one unit at a time was taken off-line, several units were taken off-line, and all the units owned by a company were taken off-line. Clearly these are not fundamental business strategies that would be employed on a regular or continuing basis by a GenCo. Nevertheless, these simple cases provide insight into what effects might be expected by implementing these approaches.

4.2.1 Physical Withholding – Single Unit Cases

Case Study Assumptions

The intentional withholding of capacity in an attempt to increase market prices has been a significant issue in all of the operating electricity markets. All markets have installed monitoring mechanisms that, in one form or another, require generation companies to justify taking units out of service, particularly during peak-load periods. To obtain a preliminary indication of the viability of physical withholding to increase profits, a series of simulation runs was conducted in

which units were taken off-line one at a time and the resultant impacts on LMPs and company profitability were calculated. For these Physical Withholding – Single Unit (PW-SU) cases, the peak-load day of the analysis year was used in the simulation, as it represented the period during which much of the available capacity needed to be utilized to meet demand. Withholding a unit on this day would have the highest probability of increasing prices throughout the systeml, and thus offer a GenCo the potential for increased profitability (i.e., would meet the definition of market power used here).

The effect that withholding a unit has on market prices depends on three considerations:

- *Unit capacity* – In general, although not always, the larger a unit is, the more it will affect market prices if it is withheld.

- *Unit location on the transmission network* – Units that are in areas of transmission congestion will have a larger impact on the market if the transmission system cannot allow replacement capacity to be utilized. In some cases, withholding a relatively small unit may have a substantial market impact, including creating load curtailments due to transmission congestion.

- *Availability of replacement capacity* – The availability (or unavailability) of replacement capacity, and its price, will determine how the market will respond to physical withholding.

In the PC case, a total of 180 units were scheduled for dispatch on the peak-load day of the analysis year. For the PW-SU cases, single units were assumed to be taken out of service, one at a time, in the day-ahead market. To meet demand, other available units were selected and scheduled for dispatch in the SYSSCHED algorithm used by the ISO simulation in the model (see Section 1.3). All GenCos, including the one withholding a unit, maintained their PC case pricing strategy of bidding available capacity at production cost.

Three conditions were imposed on this analysis. First, of the 180 units scheduled for dispatch, a number were of approximately the same size and were located at the same point in the transmission network. Since withholding a unit of the same size at the same location would produce the same market impact, it was necessary to analyze only 62 unique units for the effects of physical withholding.

Second, withholding units could create conditions where the total load could not be served due to transmission congestion. In practice, transmission system operators might be able to avoid this situation by changing the configuration of the network (e.g., closing breakers that are normally open), allowing lines to overload for a short period of time, or making other adjustments. For this analysis, the original network configuration was preserved. In the simulation, if the day-ahead market showed the need for load curtailment due to withholding, the load was reduced and all available capacity, subject to transmission limits, was scheduled for dispatch.

Third, the biggest impact from physical withholding can be expected on the peak-load day. In the analysis year, this was a day in August. Units that were withheld were assumed to be taken out of service for the entire day. Additional cases were run to determine the effect of withholding units on a low-load day and on a day when a significant number of units were off-line for maintenance.

Table 4.2.1-1 shows the results of the PW-SU case for the peak-load day. The change in company daily profits includes the loss of revenue from the unit being withheld plus the increase in revenue from the higher market prices that are paid to the company's units that continue to operate. The change in other GenCo profits reflects the change in market price that they will experience.

Only 5 of the 62 units tested showed a positive impact of physical withholding on their owners' daily operating profits for the peak-load day. The positive impact was primarily a result of where these units were on the transmission grid rather than on their size.

The table also shows that withholding other units of the same or larger capacity provided no benefit to company profitability. It is the transmission limit that resulted in the positive profit impact.

Withholding any of the other units, one at a time, either had no impact or decreased company daily profits. In these cases, the loss of revenue from the unit being withheld was not offset by the higher market prices for the units still operating.

The results also show that withholding any unit increased the daily operating profit of all other GenCos in almost all cases, due to the higher market prices that all received. The implication is that the withholding of a single unit by any one GenCo might not only decrease its own operating profits, but might serve to increase the operating profit of its competitors, since the decrease in supply raises prices for all.

One of the withheld units, Crawford 8 owned by Midwest Generation, showed very large increases in daily operating profit for the company. This was the result of a load curtailment, which yielded very high prices. While in practice this curtailment might be eliminated by reconfiguring the network and/or allowing transmission line overloads, which were not considered here, the results show that this unit could have a significant impact if it were taken off-line on a peak-load day.

Figure 4.2.1-1 shows the effect of the PW-SU cases on load-weighted zonal LMPs. There was very little effect except for a few units.

Figure 4.2.1-2 shows the distribution of changes in daily operating profits as a function of the capacity of the unit withheld. It demonstrates that an increase in the size of the unit withheld, even on a peak-load day, did not result in increased company profitability. In fact, the opposite was true. The location of the unit on the network was much more important. This is not an unexpected result, given the large amount of generation available in the State.

Table 4.2.1-1 PW-SU Cases (Case Study Assumptions) – Impact on Peak-Load Day GenCo Profits

			GenCo Peak Day Operating Profit[b] ($1000)		Other GenCos Peak Day Operating Profit[b] ($1000)		
Unit Being Withheld [a]	Owner	Capacity Withheld (MW)	PC Case	Change by With-holding	PC Case	Change by With-holding)	Load Cur-tailed (MW)
Crawford 8	Midwest Generation LLC	319	2,418	8,611	9,599	6,891	56.24
Will County 4	Midwest Generation LLC	510	2,418	99	9,599	757	-
Gibson City 1	Ameren	117	1,730	4	10,288	8	-
University Park North 4	PPL	35.25	8	1	12,010	(9)	-
University Park 1	Constellation Power	62.04	34	0	11,983	2	-
Sterling Ave(1-2) (Northwest)	Ameren	30	1,730	(0)	10,288	3	-
Pinckneyville 3	Ameren	39.5	1,730	(2)	10,288	3	-
Crawford 7G	Midwest Generation LLC	106.5	2,418	(2)	9,599	(0)	-
Raccoon Creek En. Ctr. 1	Aquila Energy	75.2	23	(3)	11,994	3	-
Shelby Energy Center 2	Reliant Energy	41.36	334	(3)	11,683	3	-
Lincoln Energy Center 8	Allegheny Power	78.02	31	(3)	11,987	6	-
Venice (new GT 2-3)	Ameren	48	1,730	(3)	10,288	3	-
Goose Creek En. Center 1	Aquila Energy	70.5	23	(4)	11,994	9	-
Pinckneyville (5-6)	Ameren	79	1,730	(4)	10,288	3	-
Equistar Morris (cogen) 1	Calpine	39	237	(5)	11,780	5	-
Kinmundy 2	Ameren	117	1,730	(5)	10,288	2	-
Powerton 5	Midwest Generation LLC	769	2,418	(5)	9,599	638	-
Crete Energy Park 4	Power Energy Partners	83.66	19	(6)	11,998	(2)	-
Pearl Station 1	Soyland Power Coop Inc.	22	8	(6)	12,009	3	-
Joppa MEPI 2	Ameren	67.68	1,730	(6)	10,288	3	-
Electric Junct (5-12)	Midwest Generation LLC	115.8	2,418	(11)	9,599	4	-
Lakeside (1-2)	City of Springfield	76	121	(12)	11,897	32	-
Lee County 8	Duke Energy	78.02	77	(14)	11,940	7	-
Hennepin 2	Dynegy Midwest Gen Inc.	215	1,062	(18)	10,955	58	-
Hutsonville 4	Ameren	77	1,730	(21)	10,288	14	-
Elwood Energy 2	Dominion Energy	159.8	602	(24)	11,415	72	-
Grand Tower CC 1	Ameren	240	1,730	(24)	10,288	44	-
Nelson (Lee County 1)	NRG Energy	274.56	511	(25)	11,506	44	-
Vermilion 2	Dynegy Midwest Gen Inc.	102	1,062	(27)	10,955	33	-
Elwood Energy III 9	Dominion Energy	161.68	602	(28)	11,415	39	-
Cordova Energy 1	MidAmerican Energy Co.	240	52	(32)	11,966	63	-
Elgin Energy Center 1-2	Ameren	234	1,730	(34)	10,288	101	-
Marion 4	Southern Ill Power Coop.	170	26	(39)	11,991	50	-
Rocky Road 1	Dynegy/NRG Energy	113.74	137	(41)	11,880	69	-
Rockford Energy Center 1	NRG Energy	147	511	(47)	11,506	83	-
Meredosia 3	Ameren	245	1,730	(56)	10,288	47	-
Holland Energy 2	Constellation Power	288	34	(57)	11,983	65	-
Joppa Steam 5	Ameren	169	1,730	(57)	10,288	48	-
Dallman 3	City of Springfield	192	121	(58)	11,897	63	-
Kendall County 4	NRG Energy	240	511	(59)	11,506	100	-
Kendall County 1	NRG Energy	240	511	(60)	11,506	120	-
Aurora (DuPage Co 3)	Reliant Energy	159.8	334	(65)	11,683	112	-
Aurora (DuPage Co 5-10)	Reliant Energy	253.8	334	(67)	11,683	129	-
Zion Energy Center 1	Calpine	150.4	237	(69)	11,780	90	-
Wood River 5	Dynegy Midwest Gen Inc.	372	1,062	(97)	10,955	129	-
Coffeen 1	Ameren	360	1,730	(97)	10,288	102	-
Duck Creek	Ameren	366	1,730	(133)	10,288	200	-
E D Edwards 3	Ameren	361	1,730	(147)	10,288	194	-
Havana 6	Dynegy Midwest Gen Inc.	428	1,062	(148)	10,955	138	-
Kincaid 2	Dominion Energy	579	602	(177)	11,415	176	-
Coffeen 2	Ameren	615	1,730	(178)	10,288	182	-
Newton 2	Ameren	610	1,730	(197)	10,288	150	-
Joliet 29_7	Midwest Generation LLC	518	2,418	(209)	9,599	240	-
Quad Cities 1	Exelon Nuclear/Midamer	855	261	(212)	11,756	183	-
Baldwin 3	Dynegy Midwest Gen Inc.	595	1,062	(221)	10,955	171	-
Waukegan 8	Midwest Generation LLC	361	2,418	(234)	9,599	318	-
Dresden 3	Exelon Nuclear	850	4,335	(317)	7,683	465	-
LaSalle 1	Exelon Nuclear	1,128	4,335	(346)	7,683	328	-
Clinton	Exelon Nuclear	930	4,335	(351)	7,683	408	-
Braidwood 2	Exelon Nuclear	1,179	4,335	(386)	7,683	217	-
Byron 1	Exelon Nuclear	1,195	4,335	(458)	7,683	937	-

[a] Each unit is withheld one at a time with all other units operating.
[b] All GenCos use production cost bidding for their operating units.

		Peak Hour Zonal LMP ($/MWh)																	
Unit Being WithHold	**Capacity Withheld (MW)**	**NI-A**	**NI-B**	**NI-C**	**NI-D**	**NI-E**	**NI-F**	**NI-G**	**IP-A**	**IP-B**	**IP-C**	**IP-D**	**AMRN A**	**AMRN B**	**AMRN D**	**AMRN E**	**CILC**	**CWLP**	**SIPC**
NONE	**0**	**87.2**	**92.7**	**77.6**	**99.3**	**54.1**	**43.7**	**47.7**	**42.6**	**42.0**	**42.5**	**41.6**	**45.2**	**41.2**	**41.5**	**42.2**	**52.2**	**46.3**	**41.1**
Crawford 8	319	114.4	123.9	97.8	265.1	72.6	48.7	47.8	40.3	41.7	42.2	41.7	44.3	41.4	41.3	42.1	50.8	45.0	41.5
Will County 4	510	98.9	128.5	109.3	147.5	69.4	45.7	47.1	43.3	43.5	43.9	42.9	48.1	42.7	42.9	43.6	60.5	49.6	42.5
Gibson City 1	117	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
University Park North 4	35.25	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
University Park 1	62.04	87.3	92.7	77.7	99.3	54.1	44.0	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Sterling Ave(1-2) (Northwest)	30	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Pinckneyville 3	39.5	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Crawford 7G	106.5	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Raccoon Creek En. Ctr. 1	75.2	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Shelby Energy Center 2	41.36	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Lincoln Energy Center 8	78.02	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Venice (new GT 2-3)	48	86.8	92.7	77.3	99.3	54.1	43.8	47.7	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Goose Creek En. Center 1	70.5	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Pinckneyville (5-6)	79	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Equistar Morris (cogen) 1	39	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Kinmundy 2	117	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Powerton 5	769	90.7	91.7	82.2	96.2	55.5	43.7	51.6	43.8	43.2	42.7	42.9	43.8	42.6	43.3	43.0	66.6	26.9	42.8
Crete Energy Park 4	83.66	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Pearl Station 1	22	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Joppa MEPI 2	67.68	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Electric Junct (5-12)	115.8	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Lakeside (1-2)	76	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Lee County 8	78.02	86.7	92.7	77.2	99.4	54.1	43.8	47.7	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Hennepin 2	215	86.8	92.7	77.3	99.3	54.1	43.9	47.8	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Hutsonville 4	77	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Elwood Energy 2	159.8	88.4	92.5	78.9	98.5	54.4	43.9	49.0	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Grand Tower CC 1	240	86.8	92.7	77.3	99.3	54.1	43.8	47.7	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Nelson (Lee County 1)	274.56	85.7	92.6	76.3	99.4	54.0	43.8	47.8	43.3	41.8	42.5	41.6	45.6	41.1	41.4	42.3	52.1	46.2	41.2
Vermilion 2	102	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Elwood Energy III 9	161.68	87.2	92.7	77.6	99.3	54.1	43.7	47.6	42.6	42.0	42.5	41.5	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Cordova Energy 1	240	86.4	92.6	77.0	99.4	54.1	43.8	47.7	42.9	41.9	42.5	41.6	45.4	41.2	41.4	42.2	52.1	46.2	41.1
Elgin Energy Center 1-2	234	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Marion 4	170	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Rocky Road 1	113.74	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Rockford Energy Center 1	147	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Meredosia 3	245	86.8	92.7	77.3	99.3	54.1	43.8	47.7	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Holland Energy 2	288	88.0	92.5	78.5	98.7	54.3	43.7	48.5	43.4	43.1	43.5	42.4	46.1	42.2	42.6	43.2	53.2	47.4	42.0
Joppa Steam 5	169	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Dallman 3	192	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Kendall County 4	240	88.3	92.5	78.8	98.5	54.4	43.6	48.8	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Kendall County 1	240	87.2	92.7	77.6	99.3	54.1	43.7	47.6	42.6	42.0	42.5	41.5	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Aurora (DuPage Co 3)	159.8	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Aurora (DuPage Co 5-10)	253.8	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Zion Energy Center 1	150.4	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Wood River 5	372	87.8	92.4	78.4	98.6	54.3	43.7	48.8	43.8	43.4	43.8	42.7	46.5	42.4	42.9	43.5	53.5	47.7	42.2
Coffeen 1	360	88.3	92.5	78.9	98.5	54.4	43.7	48.9	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Duck Creek	366	88.3	92.5	78.8	98.5	54.4	43.6	48.8	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
E D Edwards 3	361	88.3	92.5	78.9	98.5	54.4	43.6	48.8	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.8	47.7	42.3
Havana 6	428	87.7	92.4	78.4	98.6	54.3	43.7	48.8	43.8	43.4	43.7	42.7	46.5	42.4	42.8	43.4	53.6	47.8	42.2
Kincaid 2	579	88.4	92.5	78.9	98.5	54.4	43.9	49.0	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Coffeen 2	615	88.3	92.5	78.9	98.5	54.4	43.7	48.9	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Newton 2	610	88.3	92.5	78.9	98.5	54.4	43.7	48.9	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Joliet 29_7	518	88.2	92.5	78.7	98.5	54.4	43.6	48.8	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Quad Cities 1	855	83.3	92.3	74.5	99.5	53.8	43.8	48.4	44.7	41.9	42.9	42.0	46.4	41.4	41.4	42.7	52.2	46.5	41.5
Baldwin 3	595	88.3	92.5	78.9	98.5	54.4	43.7	48.9	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Waukegan 8	361	98.1	104.1	83.5	107.5	56.2	45.0	47.9	42.3	41.9	42.4	41.5	45.4	41.2	41.4	42.1	53.3	46.4	41.1
Dresden 3	850	91.5	92.3	81.8	97.5	54.8	43.9	50.2	43.9	45.4	45.3	44.0	47.4	44.0	44.7	44.9	55.4	49.6	43.5
LaSalle 1	1128	88.2	92.8	78.2	99.0	53.3	45.3	48.8	43.3	43.4	43.7	42.9	45.9	42.7	43.0	43.4	52.5	47.0	42.5
Clinton	930	90.6	92.3	81.1	97.7	54.7	43.9	50.0	44.1	45.1	45.1	43.8	47.4	43.8	44.3	44.7	55.1	49.4	43.3
Braidwood 2	1179	88.0	92.6	78.1	98.9	53.3	45.4	48.7	43.3	43.4	43.7	42.9	45.9	42.7	43.0	43.4	52.4	47.0	42.5
Byron 1	1195	110.5	119.7	95.2	118.3	59.5	48.7	50.8	42.8	43.3	43.8	42.8	47.0	42.5	42.8	43.5	56.3	48.3	42.4

Change in LMP	< 5%	5-10%	10-20%	>20%

Figure 4.2.1-1 PW-SU Cases (Case Study Assumptions) – Effect on Zonal LMP

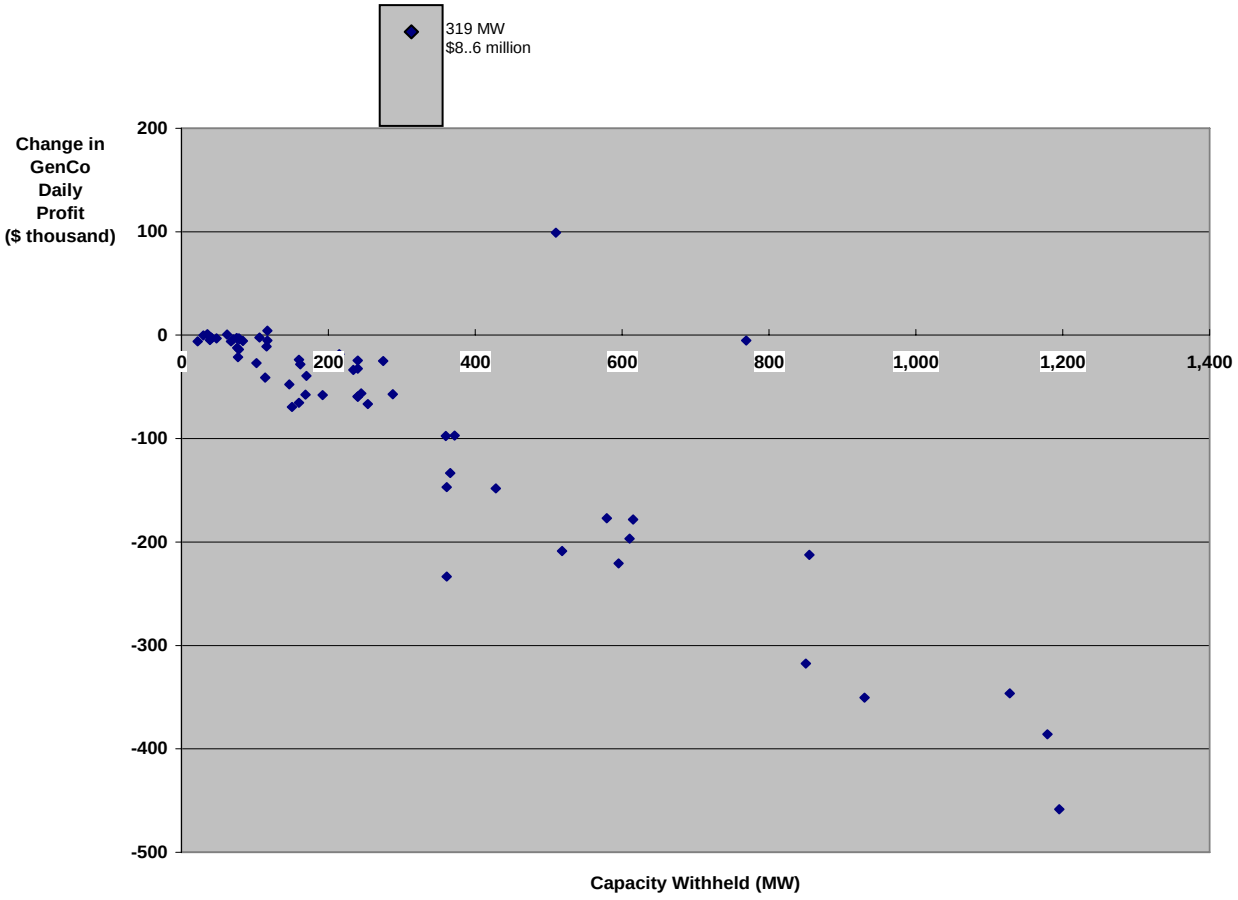

Figure 4.2.1-2 PW-SU Cases (Case Study Assumptions) – Relationship of Capacity Withheld to Daily Operating Profit

Figure 4.2.1-3 shows the location of the units that were withheld in the PW-SU cases. The color coding indicates the magnitude of the change in daily operating profitability on the peak-load day. It is evident that withholding a single unit in the northeast part of the State from among those serving the Chicago metropolitan area was the only condition that offered the potential for an increase in company profits. This is not surprising, given the transmission constraints described in Section 4.1.2. Withholding a unit, even a large capacity one, elsewhere in the State provided little or no benefit to the owners. This is true even given the transmission limits seen elsewhere in the State. The implication is that there is adequate transmission capacity to deal with the loss of individual units. A company seeking to exert market power with this strategy would need to do more than take a single unit out of service.

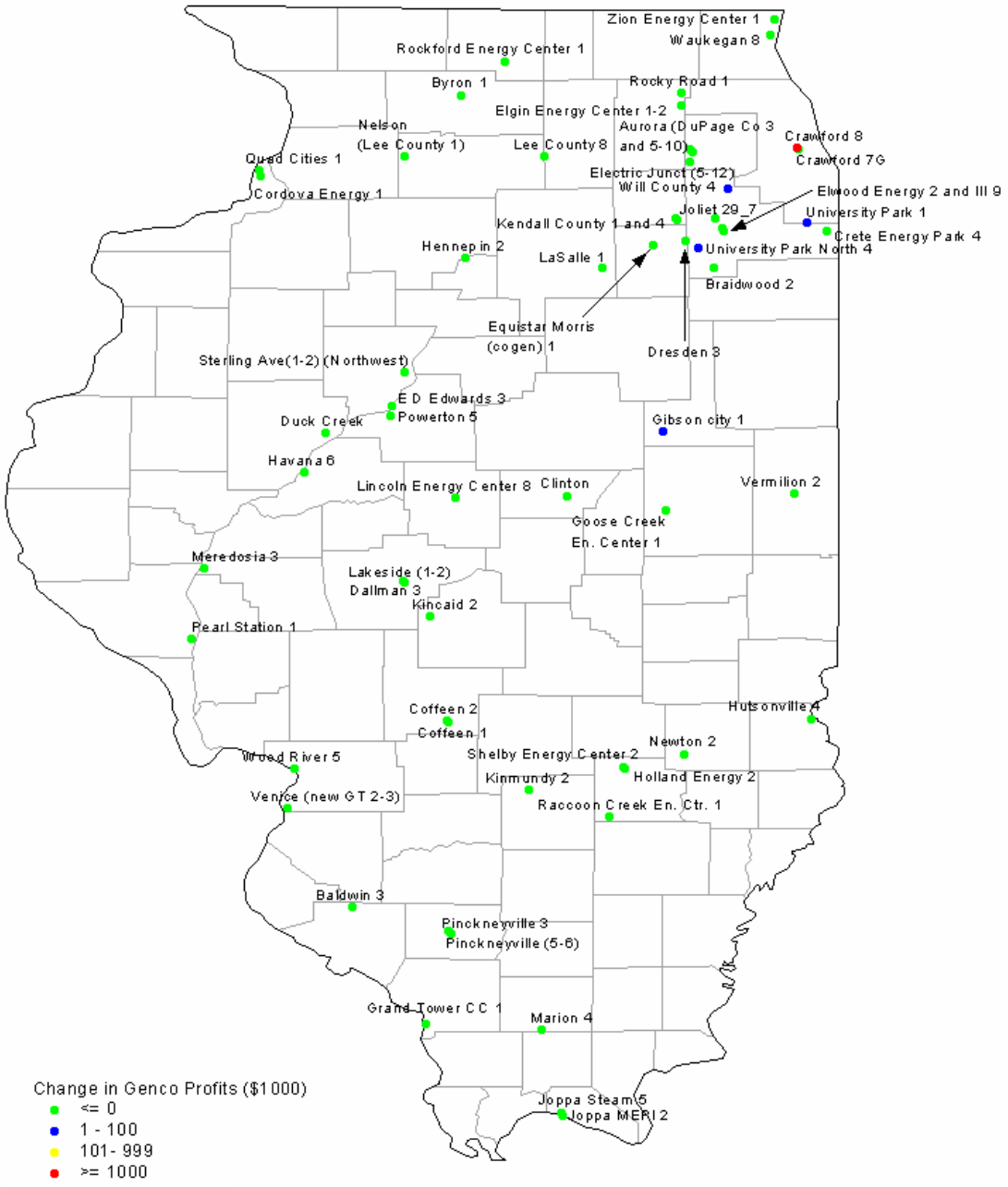

Figure 4.2.1-3 PW-SU Cases Effect of Location of Units Withheld on Company Operating Profitability

Table 4.2.1-2 shows the effect of physical withholding on low load days. One day in the analysis year when the load was low and planned maintenance outages were few was evaluated. Another day when load was low but a number of units were out on planned maintenance was also evaluated. The units showing positive impacts on the peak day were withheld on these days. In both cases the effect on company daily operating profit was not attractive.

Table 4.2.1-2 PW-SU Cases (Case Study Assumptions) – Impact on GenCo Profits on Low Load Days

			Change in GenCo Operating Profit ($1,000)	
Unit Being Withheld	**Owner**	**Capacity Withheld (MW)**	**Low Load Day with Limited Maintenance Outages**	**Low Load Day with Extensive Maintenance Outages**
Crawford 8	Midwest Generation LLC	319	1	(1)
Will County 4	Midwest Generation LLC	510	(62)	(50)
Gibson City 1	Ameren	117	(3)	0
University Park North 4	PPL	35.25	0	0
University Park 1	Constellation Power	62.04	0	0

Conservative Assumptions

An additional set of physical withholding runs was made to determine if the specific conditions used in the Case Study Assumptions were generating skewed results. Table 4.2.1-3 shows the impact of withholding single units under the Conservative Assumptions where there were no forced outages, no company-level unit commitment algorithm, and fixed operating and maintenance costs were eliminated from the production cost bidding.

Only the 5 units that showed an increase in company profitability were tested. Of these, only one, Crawford 8, showed the ability of its owner to increase company profitability by withholding it. The increase was much smaller than under Case Study Assumptions since there was no load curtailment. For all the other units, the company withholding it lost operating profit.

Thus, under both Case Study and Conservative Assumptions, withholding a single unit is not an effective strategy for a GenCo seeking to exercise market power.

Table 4.2.1-3 PW-SU Cases (Conservative Assumptions) – Impact on Peak Load Day GenCo Profits

			GenCo Peak Day Operating Profit[b] ($1,000)		Other GenCos Peak Day Operating Profit[b] ($1,000)		
Unit Being Withheld [a]	**Owner**	**Capacity Withheld (MW)**	**PC Case**	**Change by With-holding**	**PC Case**	**Change by With-holding)**	**Load Cur-tailed (MW)**
Crawford 8	Midwest Generation LLC	319	1,134	146	3,952	(137)	0
Will County 4	Midwest Generation LLC	510	1,134	(109)	3,952	(28)	0
Gibson City 1	Ameren	117	631	(0)	4,455	(0)	0
University Park North 4	PPL	35.25	(6)	(0)	5,092	(0)	0
University Park 1	Constellation Power	62.04	(41)	(0)	5,127	(0)	0

[a] Each unit is withheld one at a time with all other units operating.
[b] All GenCos use production cost bidding for their operating units.

4.2.2 Physical Withholding – Multiple Units

The previous results indicated that the withholding of a single unit, even on a peak day, would not offer much incentive to a GenCo seeking to increase profitability. The next step was to investigate the possible effects of multiple units being withheld. There are many possible combinations of multiple units that could have been tested. For the initial set of tests, units that were strategically located and might result in increased profits by their withholding were identified by an inspection of the PC case results. Because of the very large number of possible combinations, only a few illustrative cases were evaluated in this manner. A broader approach was carried out in subsequent cases.

Table 4.2.2-1 shows the results for the Physical Withholding – Multiple Unit (PW-MU) cases. The conditions that produced an increase in the peak-day operating profits were only those that resulted in the need for load curtailments. Other combinations produced no benefit to the company.

Table 4.2.2-1 PW-MU Cases (Case Study Assumptions) – Impact on Peak Load Day GenCo Profits

			GenCo Peak Day Operating Profit[b] ($1000)		Other GenCos Peak Day Operating Profit[b] ($1000)		
Units Being Withheld [a]	Owner	Capacity Withheld (MW)	PC Case	Change by With-holding	PC Case	Change by With-holding)	Load Cur-tailed (MW)
Crawford 8, Will County 4	Midwest Generation LLC	829	2,418	16,817	9,599	24,549	99
Crawford 8, Waukegan 8	Midwest Generation LLC	680	2,418	9,998	9,599	6,137	54
Crawford 7Y, 7G, 8	Midwest Generation LLC	532	2,418	9,596	9,599	8,155	30
Byron 1,2	Exelon Nuclear	2,370	4,335	9,443	7,683	43,398	69
Waukegan 7, 8	Midwest Generation LLC	689	2,418	5,540	9,599	11,074	81
Will County 4, Joliet 29_7	Midwest Generation LLC	1028	2,418	5,096	9,599	14,200	22
Will County 4, Waukegan 8	Midwest Generation LLC	871	2,418	4,656	9,599	14,389	35
Byron1, Clinton	Exelon Nuclear	2125	4,335	724	7,683	5,808	1
Havana 6, Hennepin 2	Dynegy Midwest Gen Inc.	643	1,062	(191)	10,955	187	-
DuckCreek, E.D.Edwards 3	Ameren	727	1,730	(283)	10,288	828	-
Baldwin 3, Wood River 5	Dynegy Midwest Gen Inc.	967	1,062	(331)	10,955	274	-

[a] Each group of units withheld with all other units operating.
[b] All GenCos use production cost bidding for their operating units.

4.2.3 Physical Withholding – Profitability Criteria

The number of combinations of multiple units to withhold was too large to lend itself to an assessment of all of the possibilities. Instead, a screen was needed to identify which units were likely candidates for withholding. The one tested here involved identifying the units that had the smallest profit potential for a GenCo and withholding them from the market. Table 4.2.3-1 summarizes the procedure used to implement this Physical Withholding – Profitability Criteria (PW-PR) case. An initial determination was made of the expected profitability of each unit during each hour of the next day using projected prices at each node of

the network. In the PC case, a unit with a positive projected profit would be considered to be available to the market.

In the PW-PR case, the profitability criterion was increased. A profit margin of 150% was selected as an arbitrary starting point for use here. That is, for a unit to be made available to the market, it must be projected to show a profit of 50% over its cost of operation. Units that did not show this rate of return in any hour were considered to be withdrawn for that hour.

When this initial screening of unit profitability was made, the available units were run through the CLUCRA algorithm to develop their optimal dispatch schedule. For those units that were identified as being withheld for selected hours because they failed the profitability criterion, their dispatch schedule was adjusted to reflect minimum downtimes and startup/shutdown costs. The resulting dispatch schedule was what the GenCo offered to the market for the next day. These units were bid into the market at production cost.

Table 4.2.3-1 Physical Withholding – Profitability Criteria Decision Rules

Description	Computational Procedure
GenCos project next day prices. The next day prices are projected by averaging the previous week's prices.	$LMP_{n\,h\,d+1}$ = *Average* $[LMP_{n\,h\,d}]_{d,d-5}$ *with adjustments for weekends*
GenCos apply the Physical Withholding – Profitability Criteria strategy to identify units to be withheld.	
If the expected hourly operating profit, including the profitability criteria, is positive, the unit will be made available for that hour and run through the unit commitment algorithm.	*Expected Hourly Profit* $_{g\,h\,d+1}$ $= (LMP_{n\,h\,d+1} - \alpha \times \text{Production Cost}_g) \times \text{Unit Size}_g$ $[\alpha=1.50]$ *If Expected Hourly Profit* $_{g\,h\,d+1} \geq 0$ *Unit will be offered to the market for that hour*
If the expected hourly operating profit, including the profitability criteria, is negative, the unit will be withheld for that hour.	*If Expected Hourly Profit* $_{g\,h\,d+1} < 0$ *Unit is withheld from the market for that hour*
GenCos run the unit commitment algorithm. With the projected prices for the next day and with the identification of which units will be withheld for selected hours, the CLUCRA unit commitment algorithm is run to determine which units will be offered into the market over the day. Those units that have been identified as withheld for selected hours will have their schedules adjusted to account for minimum downtime. Startup and shutdown costs will be included as part of the unit commitment.	*CLUCRA* $(LMP_{n\,d+1}) \rightarrow$ *Unit commitment with units withheld*
GenCos apply production cost bidding for units that are offered to the market.	
	d = day *h= hour* *n=network node* *g=generator*

Table 4.2.3-2 shows the units that were withheld from the market on the peak day by using the PW-PR screen and their effect on company profitability. Note that some units were withheld for several hours and others were withheld for the entire day. Similar to the single unit withholding results, there was little or no profit benefit to the companies by applying this type of physical withholding. The loss in revenue from withholding the units was not made up by the increase in market prices.

Table 4.2.3-2 PW-PR Case (Case Study Assumptions) – Impact on Peak Load Day GenCo Profits

				GenCo Peak Day Operating Profit[b] ($1000)	
Owner	**Units Being Withheld by Application of the 150% Profit Margin Screen [a]**	**Capacity Withheld (MW)**	**Hours Withheld**	**PC Case**	**Change by With-holding**
Allegheny Power	-			31	1
Ameren	Meredosia 4 Grand Tower CC 1 Grand Tower CC 2	200 240 240	1 to 24 1, 24 1, 24	1,730	4
Aquila Energy	-			23	0
Calpine	-			237	-2
Calumet Energy LLC	-			-5	0
City of Springfield	-			121	3
Constellation Power	Holland Energy 1 Holland Energy 2	288 288	1 to 24 1	34	-1
Dominion Energy	State Line 3 State Line 4	197 318	1 to 24 1 to 24	602	6
Duke Energy	-			77	-1
Dynegy Midwest Generation Inc.	Havana (1-5) Hennepin 1 Wood River 1 Wood River 2 Wood River 3	238 74 46.3 46.3 46.3	1 to 24 1 to 6 1 to 24 1 to 24 1 to 24	1,062	9
Dynegy/NRG Energy	-			137	0
Exelon Nuclear	-			4,335	3
Exelon Nuclear/Midamerican Energy	-			261	-6
MidAmerican Energy Co.	Cordova Energy 1 Cordova Energy 2	240 240	1, 24 1, 24	52	0
Midwest Generation LLC	Collins 1 Collins 2 Collins 3 Crawford 7G Fisk 19	554 554 530 106.5 326	1 to 24 1 to 24 1 to 24 9 to 24 8 to 24	2,418	68
NRG Energy	Kendall County 1 Kendall County 2 Kendall County 3 Kendall County 4 Nelson (Lee County 1) Nelson (Lee County 2) Nelson (Lee County 3) Nelson (Lee County 4) Rockford Energy Center 3	240 240 240 240 274.56 274.56 274.56 274.56 147	1, 24 1, 24 1, 24 1, 24 1, 24 1, 24 1, 24 1, 24 1 to 10, 23, 24	511	-1
Power Energy Partners	-			19	2
PPL	-			8	0
Reliant Energy	-			334	0
Southern Illinois Power Coop.	Marion 1 Marion 2 Marion 3	34 34 34	1 to 24 1 to 24 1 to 24	26	4
Southwestern Electric Coop.	-			-3	0
Soyland Power Coop Inc.	Pearl Station 1	22	1,2,24	8	0

Additional cases were run with changes in the profitability criterion, both higher and lower. The same pattern of limited impact on company profitability was observed. It can be concluded that the profitability criterion does not provide an adequate identification of units that could be withheld to increase overall company profitability.

4.2.4 Physical Withholding – System Reserve Criteria

Another screen was used in an attempt to identify units that a company might consider for physical withholding. This was based on using the system reserve – the generating capacity that is available in excess of the load. Table 4.2.4-1 summarizes the decision rules for this approach.

Table 4.2.4-1 Physical Withholding – System Reserve Criteria Decision Rules

Description	Computational Procedure
GenCos project next day prices. The next day's price for each hour at each node of the network is projected as inversely proportional to the system reserve. That is, as the reserve margin decreases, prices are projected to increase proportionally. This is a simple projection approach but captures the anticipated effects of high demands on the system on prices.	*System Reserve (SR)* $= (\text{Available Capacity}_{h\ d+1} \ / \ \text{Load}_{h\ d+1} \ - \ 1)$ $LMP_{n\ h\ d+1} = LMP_{n\ h\ d} \ (SR_{h\ d} / SR_{h\ d+1})$
GenCos apply the Physical Withholding – System Reserve Criteria strategy to adjust the unit commitment. If the system reserve margin is expected to be lower than a trigger point, units are considered for withholding. Units are rank-ordered by the projected price (LMP) from highest to lowest. Capacity to be withheld is that which will bring the SR down by a target amount. Units are withheld up to a specified portion of the company's total capacity. If the system reserve margin is expected to be higher than the trigger point, no units are withheld.	 $If\ SR_{h\ d+1} \leq \theta$ [θ=55%] *Unit ranking: Highest LMP, second highest, …* *Target reduction in system reserve by withholding = σ* [σ=5%] $Capacity\ Withheld = \sum_{\sigma} Units\ in\ rank\ order$ *where Capacity Withheld ≤ δ x Company Capacity* [δ=25%] $If\ SR_{h\ d+1} > \theta$ *No withholding*
GenCos run the unit commitment algorithm. With the projected prices for the next day and with the identification of which units will be withheld for selected hours, the CLUCRA unit commitment algorithm is run to determine which units will be offered into the market over the day. Those units that have been identified as withheld for selected hours will have their schedules adjusted to account for minimum downtime. Startup and shutdown costs will be included as part of the unit commitment.	*CLUCRA* $(LMP_{n\ d+1}) \rightarrow$ *Unit commitment with units withheld*
GenCos apply production cost bidding for units that are offered to the market.	
	d = day *h= hour* *n=network node* *g=generator*

Case Study Assumptions

In the Physical Withholding – System Reserve Criteria (PW-SR) case, the GenCo strategy was based on identifying when the system reserve was expected to be low and then withholding capacity in an attempt to drive up prices. It recognized the fact, as was shown previously, that during periods of high system reserve (i.e., low loads, high available generation) there was ample capacity for competitors to take up the slack from any units that were withheld from service. By identifying times when the system reserve was low, a company could pinpoint those hours when withholding a unit would have the biggest impact. Based on a number of experiments with the EMCAS model, a system reserve of 55% was selected as the trigger point for companies to implement this strategy. During periods when the system reserve was higher, there was no benefit to withholding. From the load and available capacity projections, the system reserve was projected to be below 55% for 108 hours during the analysis year. (Under Conservative Assumptions, it was below 55% for 48 hours during the analysis year.)

With the projected system reserve for the next day, GenCos projected the next day's prices. Instead of using the average of the previous week's prices, as was done in earlier cases, a more forward-looking approach was used in an attempt to take better advantage of expected high price conditions. The next day's prices were projected to be inversely proportional to the system reserve. These projections were then used in the unit commitment algorithm (i.e., the CLUCRA described in Section 1.3) to develop an initial listing of units to be offered into the next day's market.

If the system reserve was expected to be at or below the trigger point, the GenCos considered withholding units to increase prices. Their portfolio of units was rank-ordered by the LMP of the bus they were connected to. Generators at buses with the highest LMPs were ranked first, as they would likely have the biggest impact on prices if they were taken out of service. The amount of capacity to be withheld was that which would bring the system reserve lower by a target amount. For these cases, the target amount was chosen to be 5%. This value was selected after experimenting with a number of possible values. Much larger values were shown to generate withholding that was too extensive. Much smaller values restricted the withholding to being inconsequential.

With the target amount of capacity to be withheld when the trigger point was reached, GenCos proceeded through the rank-ordered list and withheld enough capacity to meet the target. A limit was placed on the total amount of a company's capacity that would be withheld. In these cases, the limit was set at 25% of the total company capacity. This was done to avoid extreme conditions that were not practical and not of interest.

Cases in which individual companies applied the PW-SR strategy one at a time were studied. Also studied was a case in which all companies pursued the strategy at the same time. Table 4.2.4-2 shows the effects on GenCo peak day profitability when the Case Study Assumptions were used. In all cases, the application of this strategy led to the need for load curtailments. This strategy enabled companies to not only identify how much capacity could be withheld to affect the system reserve, but also where that withholding would have the biggest effects. There were clear profit benefits to the companies by using this method to withhold

capacity. For the largest three companies, peak day profits increased between 100% (Ameren) to 668% (Midwest Generation) if each were to apply the strategy by itself. If all companies applied the strategy at the same time, the company profitability would increase by more than 17 times. In addition to benefits to the companies employing the strategy, there were significant benefits to other GenCos as well, as shown on the table. Figure 4.2.4-1 shows the location of the units withheld by the application of the PW-SR strategy. They are all in areas affected by the transmission congestion discussed in Section 4.1.2.

Table 4.2.4-2 PW-SR Case (Case Study Assumptions) – Impact on GenCo Peak Day Profits

			GenCo Peak Day Operating Profit ($1,000)		Other GenCo Peak Day Operating Profit ($1,000)		
GenCo Applying PW-SR Strategy	**Units Withheld**	**Capacity Withheld (MW)**	**PC Case**	**Change by With-holding**	**PC Case**	**Change by With-holding**	**Load Cur-tailed (MW)**
Exelon Nuclear	Byron 1	1,195	4,140	9,487	7,033	42,091	70
	Byron 2	1,175					
Midwest Generation LLC	Joliet 29_7	518	2,037	13,602	9,136	40,926	208
	Joliet 29_8	518					
	Crawford 7Y	107					
	Waukegan 6	100					
	Waukegan 7	328					
	Waukegan 8	361					
Ameren	E D Edwards 1	117	1,647	1,728	9,526	1,544	55
	E D Edwards 2	262					
	E D Edwards 3	361					
	Duck Creek	366					
	Coffeen 1	360					
	Meredosia 3	245					
Dynegy Midwest Generation Inc.	None	0	1,037	-	10,136	-	-
Dominion Energy	None	0	527	-	10,646	-	-
All Companies							
Exelon Nuclear	Byron 1	1,195	4,140	40,628	7,033	222,556	1,089
	Byron 2	1,175					
Midwest Generation LLC	Joliet 29_7	518	2,037	81,047	9,136	182,138	
	Joliet 29_8	518					
	Crawford 7Y	107					
	Waukegan 6	100					
	Waukegan 7	328					
	Waukegan 8	361					
Ameren	E D Edwards 1	117	1,647	14,977	9,526	248,207	
	E D Edwards 2	262					
	E D Edwards 3	361					
	Duck Creek	366					
	Coffeen 1	360					
	Meredosia 3	245					

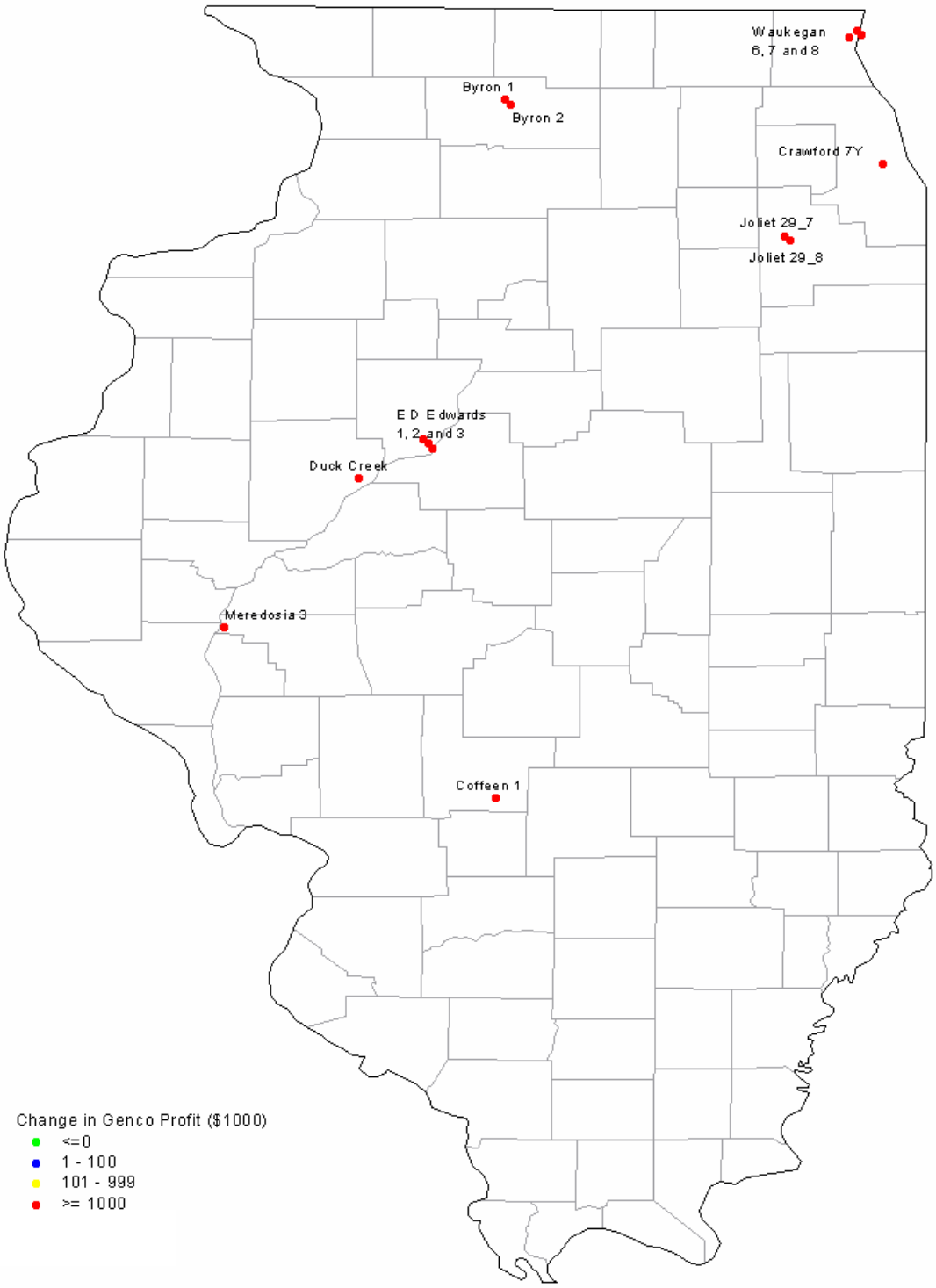

Figure 4.2.4-1 PW-SR Cases (Case Study Assumptions) – Effect of Location of Units Withheld on Company Operating Profitability

Figure 4.2.4-2 shows the effect of the PW-SR strategy on the daily maximum zonal LMPs. Recall that in this strategy, only production cost bidding was used by the companies. There was no strategic price bidding by any company. In some cases, the LMP increases were substantial. With all companies applying the strategy, the LMPs reached into the thousands. This is a clear indication of the limitations of the transmission system to allow the capacity that was available to replace the withdrawn capacity. The result was load curtailments and very high prices.

Company Withholding	None	Exelon	Midwest Generation	Ameren	Dynegy	Dominion	All
Capacity Withheld (MW)	0	2370	1932	1711	0	0	6013
Zone	Maximum Zonal LMP ($/MWh)						
NI-A	87.2	108.0	170.0	91.9	83.7	83.7	3,664.9
NI-B	92.7	140.5	932.7	116.3	94.2	94.2	4,341.8
NI-C	77.6	89.4	171.6	82.3	71.5	71.5	2,901.1
NI-D	99.3	87.9	310.5	81.2	65.9	65.9	4,184.9
NI-E	54.1	50.8	120.4	46.5	41.8	41.8	1,907.7
NI-F	43.7	44.8	78.2	42.4	38.4	38.4	653.9
NI-G	47.7	54.9	83.5	45.0	45.2	45.2	1,309.7
IP-A	43.2	51.1	44.4	44.4	44.4	44.4	649.8
IP-B	42.1	43.4	44.4	41.3	41.8	41.8	131.2
IP-C	42.6	44.1	45.0	42.0	42.2	42.2	42.0
IP-D	41.6	42.9	43.9	41.3	41.3	41.3	41.2
AMRN-A	45.3	48.8	54.0	44.5	44.5	44.5	400.8
AMRN-B	41.2	43.7	45.5	40.7	41.0	41.0	40.7
AMRN-D	41.6	42.6	43.8	40.9	41.3	41.3	45.7
AMRN-E	42.3	43.3	44.0	41.9	42.0	42.0	41.9
CILC	52.2	55.8	128.3	3840.6	47.8	47.8	5,987.9
SIPC	41.1	41.8	42.6	41.3	41.2	41.2	41.2
CWLP	46.3	49.3	51.8	44.0	44.7	44.7	109.3

Change in LMP	< 5%	5-10%	10-20%	>20%

Figure 4.2.4-2 PW-SR Cases (Case Study Assumptions) – Impact on Zonal LMP

Table 4.2.4-3 shows the effect on consumer costs. The increases were substantial, ranging from a 100% increase for the case where Ameren applied the PW-SR strategy to a 550% increase if Midwest Generation applied the strategy. If all companies applied the strategy, consumer peak day costs increased by almost a factor of 20. These results are consistent with the transmission congestion effects described in the PC case. The NI zones saw the biggest impacts from an attempt to exercise market power, in this case by using physical withholding. The IP, AMRN, and SIPC zones were impacted to a smaller degree. The CILC zone showed some vulnerability to this market power strategy.

Table 4.2.4-3 PW-SR Cases (Case Study Assumptions) – Impact on Peak Day Consumer Costs

		Company Applying PW-SR Strategy					
Zone	PC Case Peak Day Consumer Costs ($1,000)	Exelon Nuclear	Midwest Generation LLC	Ameren	Dynegy	Dominion Energy	All
		Change in Consumer Costs ($1,000)					
NI-A	3,615	16,709	17,344	176	0	0	82,653
NI-B	9,361	49,560	93,901	1,014	0	0	242,376
NI-C	4,171	14,866	20,199	190	0	0	75,414
NI-D	10,136	40,081	79,345	1,019	0	0	223,983
NI-E	4,532	7,446	14,521	223	0	0	49,423
NI-F	482	645	612	12	0	0	2,115
NI-G	331	453	342	(19)	0	0	3,161
IP-A	973	200	121	(186)	0	0	5,129
IP-B	559	90	50	(16)	0	0	(133)
IP-C	1,316	198	137	(29)	0	0	(1,362)
IP-D	776	61	54	(3)	0	0	(72)
AMRN-A	780	360	538	(3)	0	0	2,389
AMRN-B	1,224	166	122	(10)	0	0	(317)
AMRN-D	284	40	20	(6)	0	0	(67)
AMRN-E	1,319	205	152	(20)	0	0	(721)
CILC	1,436	2,321	4,200	43,122	0	0	49,511
SIPC	267	3	3	0	0	0	(9)
CWLP	525	(36)	(56)	(89)	0	0	163
Total	**42,087**	**133,367**	**231,606**	**45,377**	**0**	**0**	**733,637**

It should be noted that there are several parameters that affect the results of this strategy: the system reserve trigger point (chosen as 55% here), the system reserve reduction target (chosen as 5% here), and the maximum portion of company capacity to be withheld (chosen as 25% here). The values chosen here for these parameters are not intended to imply that these are the best or most realistic. Rather, they represent levels that provide insight into how this strategy might function. Sensitivity studies over a wide range of these values would be appropriate for further analysis.

Conservative Assumptions

Table 4.2.4-4 shows the effect of the application of this strategy under the Conservative Assumptions. With one exception, the results are the same as for the Case Study Assumptions, but the profit increases were more modest, since the prices were lower under these assumptions. Also, because of the larger amount of generation available due to the absence of forced outages and the company-level unit commitment under the Conservative Assumptions, there was less load curtailment. The exception is the application of this strategy by Exelon Nuclear. For this company, it did not increase profitability, as there was adequate generation and transmission capacity to replace the units withheld. There was no need for load curtailment in this case.

Table 4.2.4-4 PW-SR Case (Conservative Assumptions) – Impact on GenCo Peak Day Profits

			GenCo Peak Day Operating Profit ($1,000)		Other GenCo Peak Day Operating Profit ($1,000)		
GenCo Applying PW-SR Strategy	**Units Withheld**	**Capacity Withheld (MW)**	**PC Case**	**Change by With-holding**	**PC Case**	**Change by With-holding**	**Load Cur-tailed (MW)**
Exelon Nuclear	Byron 1	1,195	2,478	(675)	2,608	814	-
	Byron 2	1,175					
Midwest Generation LLC	Joliet 29_7	518	1,134	1,829	3,952	5,501	44
	Joliet 29_8	518					
	Crawford 7Y	107					
	Waukegan 6	100					
	Waukegan 7	328					
	Waukegan 8	361					
Ameren	E D Edwards 1	117	631	1,507	4,455	749	60
	E D Edwards 2	262					
	E D Edwards 3	361					
	Duck Creek	366					
	Coffeen 1	360					
	Meredosia 3	245					
	Meredosia 4	200					
Dynegy Midwest Generation Inc.	None	0	425	-	4,661	-	-
Dominion Energy	None	0	114	-	4,971	-	-
All Companies							
Exelon Nuclear	Byron 1	1,195	2,478	13,359	2,608	61,205	253
	Byron 2	1,175					
Midwest Generation LLC	Joliet 29_7	518	1,134	25,076	3,952	49,487	
	Joliet 29_8	518					
	Crawford 7Y	107					
	Waukegan 6	100					
	Waukegan 7	328					
	Waukegan 8	361					
Ameren	E D Edwards 1	117	631	3,567	4,455	70,997	
	E D Edwards 2	262					
	E D Edwards 3	361					
	Duck Creek	366					
	Coffeen 1	360					
	Meredosia 3	245					
	Meredosia 4	200					

4.2.5 Physical Withholding – Companywide

An extreme case of physical withholding would be for a company to pull all of its capacity out of service. Obviously, this would not improve the company's profitability; nevertheless, some of the indicators used by FERC to determine if a company has market power (e.g., the supply margin assessment, the residual supply index) are based on determining if load can be met without any contribution from the company being evaluated. With the concentration of capacity in a few companies, such as is the case in Illinois, this strategy could be expected to result in significant amounts of unserved energy. Table 4.2.5-1 shows the results of the Physical Withholding – Companywide (PW-CW) case. The amount of load that would need to be curtailed if each company took all of its capacity out of service is shown along with the zonal LMP effect.

Table 4.2.5-1 PW-CW Case – Load Curtailments and Zonal Price Effects

Generation Company	Capacity Withheld (MW)	Load Curtailed during Peak Hour of Peak Day (MW)	Maximum Zonal LMP during Peak Day		Load Curtailed during Off-Peak Hours of Peak Day (MW)
			($/MWh)	Zone	
Exelon Nuclear	9,947	1,237	5,051	NI-B	0
Midwest Generation	8,063	1,867	6,307	NI-D	0
Ameren	6,815	106	1,775	NI-A	0
Dynegy	3,812	0	96	NI-D	0
Dominion Energy	3,121	0	130	NI-D	0
City of Springfield	610	28	7,342	CWLP	0

The results show that Exelon Nuclear, Midwest Generation, Ameren, and the City of Springfield have market power using these criteria. In the case of Exelon Nuclear and Midwest Generation, the amount of load that would have to be curtailed was extensive and would likely have resulted in emergency conditions. In the case of Ameren and the City of Springfield, the amount of curtailment was small enough that it might have been managed with changes to the network configuration, which were not considered here. Nevertheless, the impact on zonal LMPs was substantial.

4.2.6 Physical Withholding Summary

The following summary observations can be made with respect to physical withholding strategies*:*

- Physically withholding individual units increased company operating profits only when applied to a few selected units. This was true for both the Case Study Assumptions and the Conservative Assumptions. For most units, withholding it from service on peak days resulted in a decrease in company operating profit. For a very few units that were critical to meeting load during peak hours, withholding it from service could create a situation where the demand could not be met without some change to the transmission

network configuration. Unserved energy could result in large increases in prices and company profitability. However, this situation is generally avoided by companies seeking to maintain good customer relations.

- Withholding multiple units provided an increase in company profitability. However, this appeared to result only in cases where there was the need for load curtailment associated with the withholding.

- Unit profit margin did not serve as a good screen for a company to identify combinations of units for withholding. The change in profitability by the application of this screen was small.

- System reserve did appear to be a good screen for identifying units to withhold. If it was used, units could be withheld that provided a significant increase in company peak day profitability. Very high LMPs and very high increases in consumer costs also resulted from the application of this approach. Under Conservative Assumptions, the same was generally true except that the increases in profits were more modest. The exception to this result was Exelon Nuclear, for whom the application of this strategy did not increase profitability.

- The same zones that experienced high LMPs due to transmission congestion under PC case conditions were shown to be the most impacted by the application of a physical withholding strategy; i.e., the NI zones. The IP, AMRN, and SIPC zones were less impacted. The CILC zone showed a degree of vulnerability.

- Using the criteria of determining if load could be met without any contribution from a company indicated that Exelon Nuclear, Midwest Generation, Ameren, and the City of Springfield had market power. Load could not be met if all their units were taken out of service. Dynegy and Dominion Energy did not have market power, according to this measure.

4.3 ECONOMIC WITHHOLDING CASES

Economic withholding strategies in a competitive electricity market differ from physical withholding strategies in that the generation capacity is not taken off-line. Rather, it is made available to the market, but at increased prices. Analogous to physical withholding, the effect that economic withholding has on market prices depends on the size of the unit that has its price increased, the unit's location in the transmission network, and the availability of other capacity at lower prices.

4.3.1 Economic Withholding – Single Unit

To determine how economic withholding might affect the Illinois market, EMCAS simulation runs were conducted in which single units were assumed to have their bid prices increased. For the initial runs, attention was focused on the units that demonstrated a positive

impact on company profitability in the physical withholding case described in the previous section. For these individual units, the price at which capacity was bid into the market was increased in multiples between 1.25 and 10 times above the unit's production cost. Two cases were run for each unit. In the first, the unit's bid price was increased for the entire peak-load day. In the second, the price increases were applied only during five peak-load hours. Table 4.3.1-1 shows the results of these simulations.

Table 4.3.1-1 Economic Single Unit Withholding (Case Study Assumptions) – Impact on Peak Load Day GenCo Profits

Unit Being Withheld	Owner	Capacity With Increased Bid Prices (MW)	PC Case Peak Day Oper-ating Profit ($1000)	Hours that Prices Are Increased	Change in Company Peak Day Operating Profit With Increase in Bid Price Over Production Cost ($1000)					
					1.25	1.5	1.75	2.0	5.0	10.0
Crawford 8	Midwest Generation LLC	319	2,418	All Hours	-9.8	4.5	13.2	4.3	22.0	39.6
				Peak Hours	0.0	0.0	0.0	0.0	-58.5	5.5
Will County 4	Midwest Generation LLC	510	2,418	All Hours	-17.0	-46.7	-55.5	-65.9	-178.2	-189.9
				Peak Hours	0.0	0.0	0.0	0.0	-44.3	-74.7
Gibson City 1	Ameren	117	1,730	All Hours	4.3	4.3	4.3	4.3	4.3	4.3
				Peak Hours	1.9	1.9	1.9	1.9	1.9	1.9
University Park North 4	PPL	35.25	8	All Hours	0.4	0.8	0.8	0.9	0.8	0.9
				Peak Hours	-0.1	0.0	0.0	0.0	0.0	0.0
University Park 1	Constellation Power	62.04	34	All Hours	0.4	0.4	0.4	0.4	0.4	0.4
				Peak Hours	0.3	0.2	0.2	0.3	0.2	0.2

Economic withholding of single units had a very small impact on company peak day profitability. In some cases, the effect was negative, since the price increase reduced the unit's competitiveness in the market and its dispatch schedule was reduced. In all cases, the profitability increase was below, or at best equal to, what was experienced by simply physically withholding the unit. The implication is that single unit economic withholding resulted in the unit being dispatched less. There was adequate generation and transmission capacity available to allow other units to meet the load.

4.3.2 Economic Withholding – Companywide Withholding

A broader case of an economic withholding strategy is for a GenCo to increase the bid prices on all units in its portfolio. To determine the effectiveness of this strategy, EMCAS simulation runs were conducted in which the bid prices of all units for a selected GenCo were increased in multiples above production cost for the peak-load day. All other GenCos were assumed to maintain their bid prices at production cost. The results for each company are documented in the following sections. It should be restated that these simulations are not intended to imply that any company would employ this type of strategy. Rather, they are

designed to identify what might be possible under the market configuration used in the simulation.

Exelon Nuclear

Case Study Assumptions

Figure 4.3.2-1 shows the results of companywide economic withholding as applied to the Exelon Nuclear portfolio of generators. The company's operating profits and generation level for the peak day are shown as a function of the amount that the price was increased above production cost. In the simulations, all units in the company's portfolio had their market bid prices increased at the same rate for the entire day. Figure 4.3.2-2 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested.

The results showed that for price increases up to about five times production cost, the company lost both generation (i.e., was dispatched less) and daily operating profit in the market. Up to this point, there was less expensive generation and adequate transmission capacity available to meet the load, both from in-state and out-of-state sources. As shown on Figure 4.3.2-2, during peak hours about 6,000 MW of the company's generating capacity was needed to meet the load. For this portion of capacity, prices could be increased considerably and still be accepted in the market. This is shown by the flattening of the generation curve in Figure 4.3.2-1. The Dresden, Byron, and LaSalle plants were the units that were still dispatched, even at the higher prices. Transmission limits kept cheaper capacity from displacing these higher-priced units. There is, however, a technical limit that keeps this from being a practical result. Under the market rules employed here, GenCos that have units that must run to stay within their technical performance limits must adjust their bid prices so as to ensure that their units are dispatched. Since Exelon's units are all nuclear plants, they are not readily cycled to match the dispatch schedule that would result from this pricing scheme.

These results also showed that Exelon Nuclear would not be able to increase the prices of its nuclear generators significantly for the entire day without running the risk that they would be outbid in the market during lower-load hours and thus have a dispatch schedule that would not be technically feasible. An alternative strategy would be to increase prices only during peak hours. Figure 4.3.2-3 shows these results. Prices were increased only during the period from 2 pm to 6 pm, when the load was the greatest. This was a far more attractive strategy from the company's perspective. The company's generation level was reduced only a small amount even as prices increased significantly. Even a twenty-fold price increase did not measurably change the company's generation level. In fact, prices could conceivably be raised even higher, since the generation level flattened out. This is in the absence of any consumer price response and/or regulatory controls..

At the twenty-fold increase above production cost, the company's capacity-weighted average bid price was about 315 $/MWh, which is considerably more expensive than other available capacity. The Exelon price increases caused an adjustment to the loading of the transmission system as the transmission-constrained dispatch (i.e., the SYSCHED algorithm in EMCAS) sought to replace the now-more-expensive Exelon units. However, cheaper generation

was not able to displace these units because of transmission limitations. Table 4.3.2-1 shows the transmission components that were operated at their capacity limits at the twenty-fold price increase level. The location of these components was shown on Figure 4.1.2-1. An additional component, the Moweaqua line, also reached its capacity limit. Some lines (shown in normal print) remained at their capacity limits, as was seen in the PC case. Some lines (shown in bold) that were not congested under PC case conditions became congested as the system attempted to displace the expensive Exelon units. These newly congested lines were all outside the NI zones as the system sought to bring in power from elsewhere. Other lines (shown shaded) actually experienced a relaxation of congestion as the system adjusted to the price increases. This relaxation, however, did not allow for enough additional lower-cost-power to be dispatched to keep prices from rising.

This pricing strategy impacted the cost of electricity for consumers. Figure 4.3.2-4 shows the impact of the price increments on zonal LMPs. Figure 4.3.2-5 shows the impact on consumer costs. The results show that the company strategy had a significant impact. As was seen in the PC case discussion of transmission loading, the NI zones were the most impacted by the price increases. The transmission limits in these areas did not allow cheaper power to be brought in. In effect, the company could set prices at any level. Again, this should not be interpreted as an indication that the company would, in practice, exercise this market power.

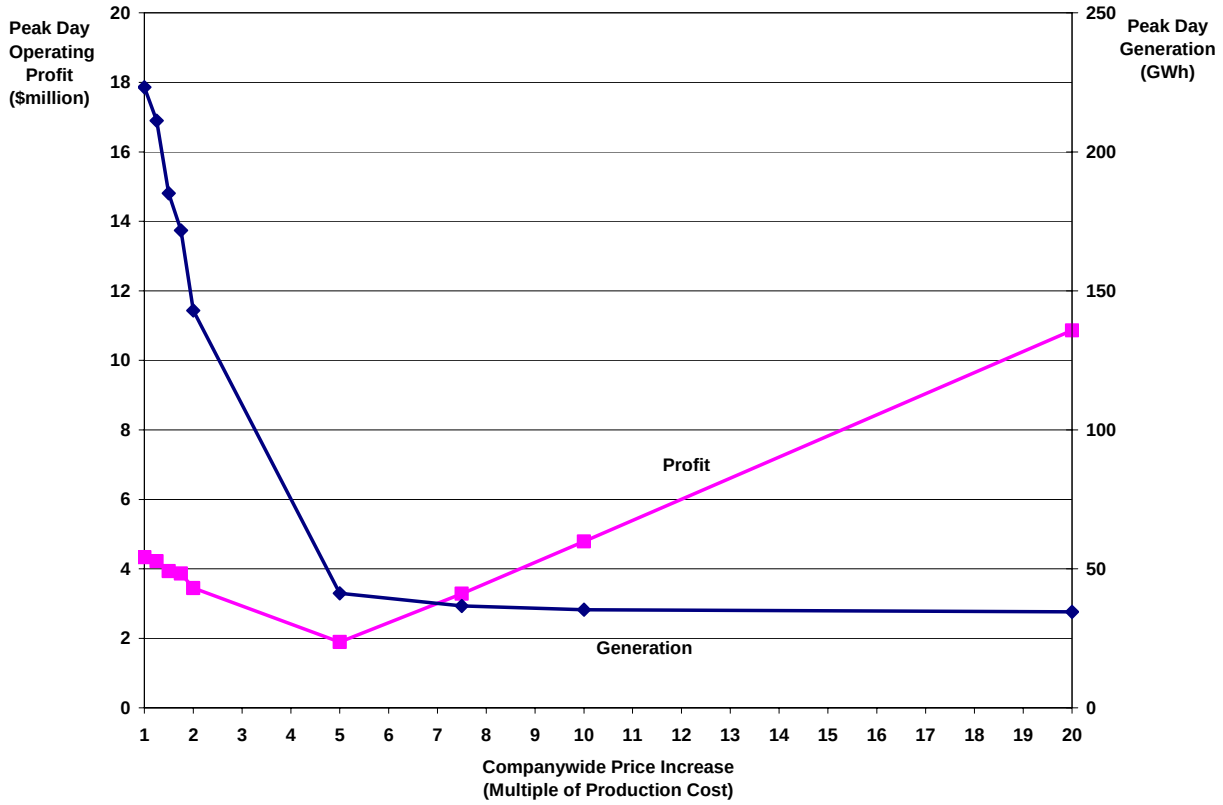

Figure 4.3.2-1 Exelon Nuclear Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

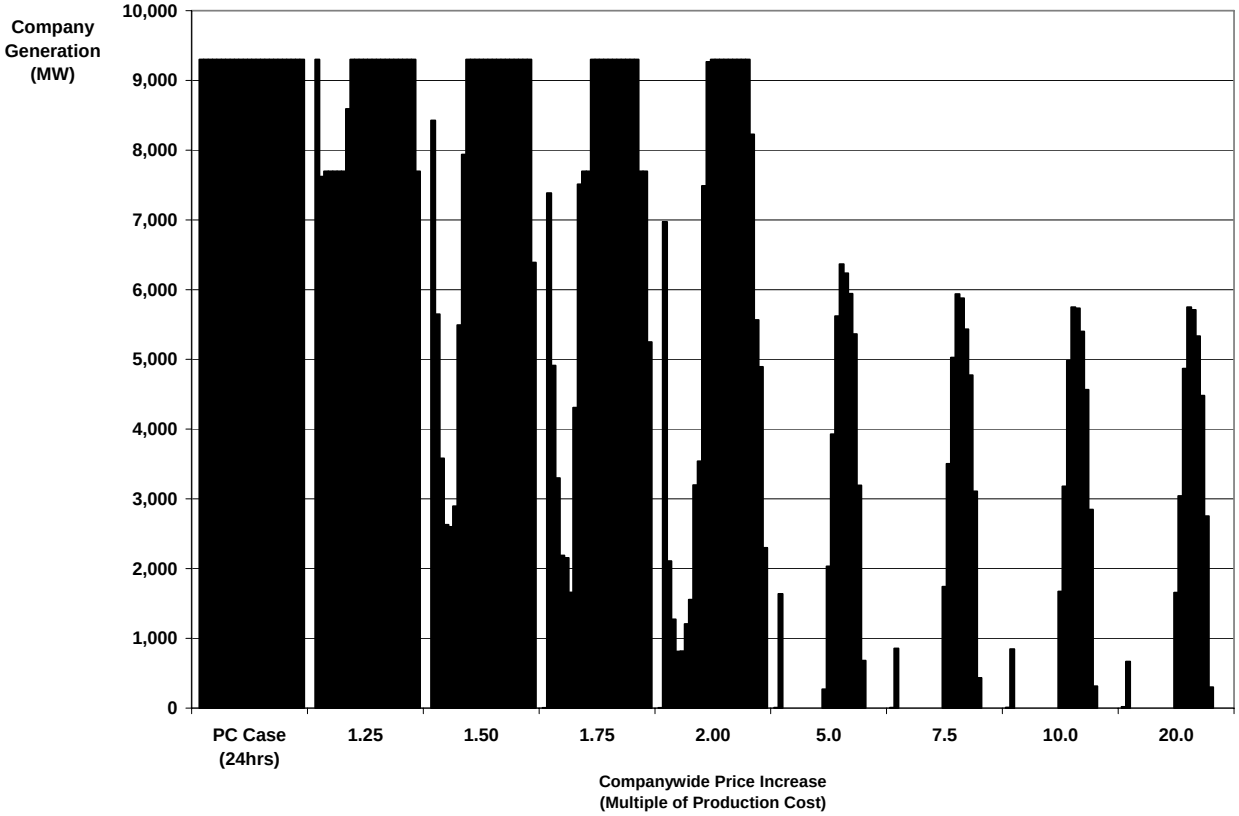

Figure 4.3.2-2 Exelon Nuclear Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

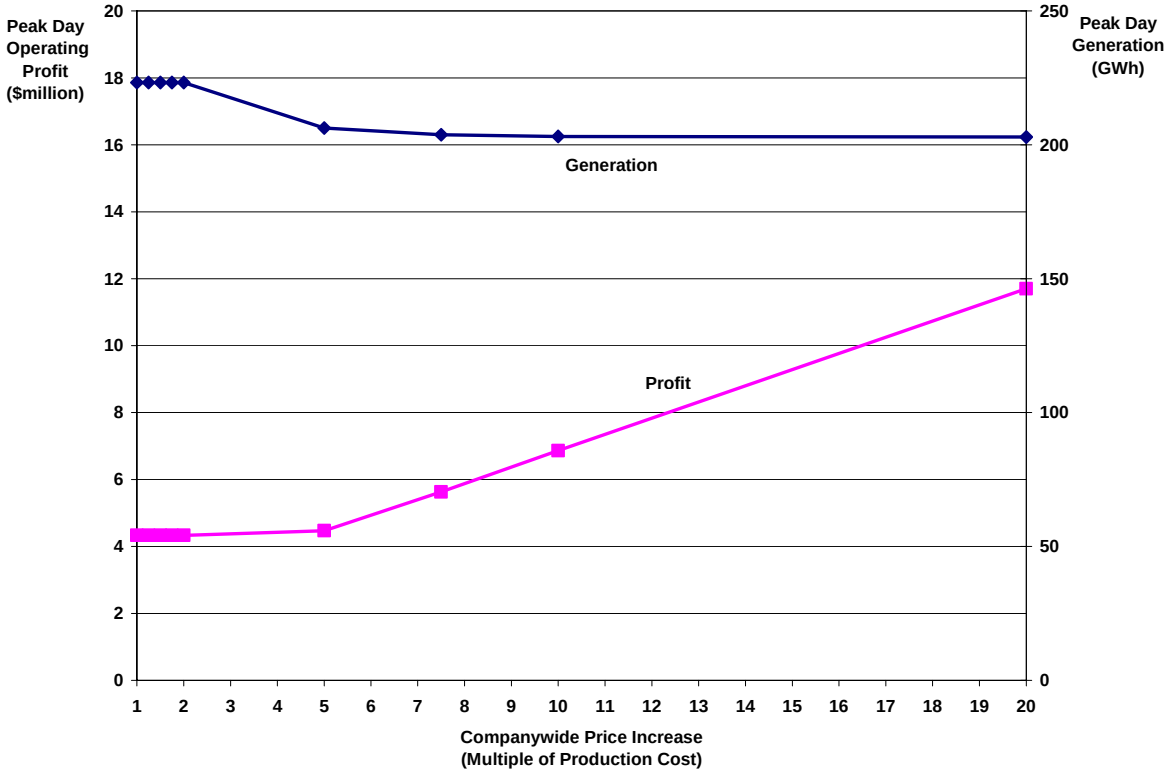

Figure 4.3.2-3 Exelon Nuclear Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-1 Transmission Components at Capacity Limits under Exelon Nuclear 20-Fold Peak Hour Price Increase (Case Study Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-C							
32355_32369	**PANA IP**	**MOWEAQ T**	**IP-C**	**IP-C**	**138**	**kV**	**Line**
32368_32369	**RT 51 TP**	**MOWEAQ T**	**IP-C**	**IP-C**	**138**	**kV**	**Line**
AMRN-B							
30395_31445	**COFFEEN**	**PANA**	**AMRN-B**	**AMRN-B**	**345**	**kV**	**Line**
30439_31351	**CROSSVL**	**NORRIS**	**AMRN-B**	**AMRN-B**	**138**	**kV**	**Line**
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer
CILC							
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

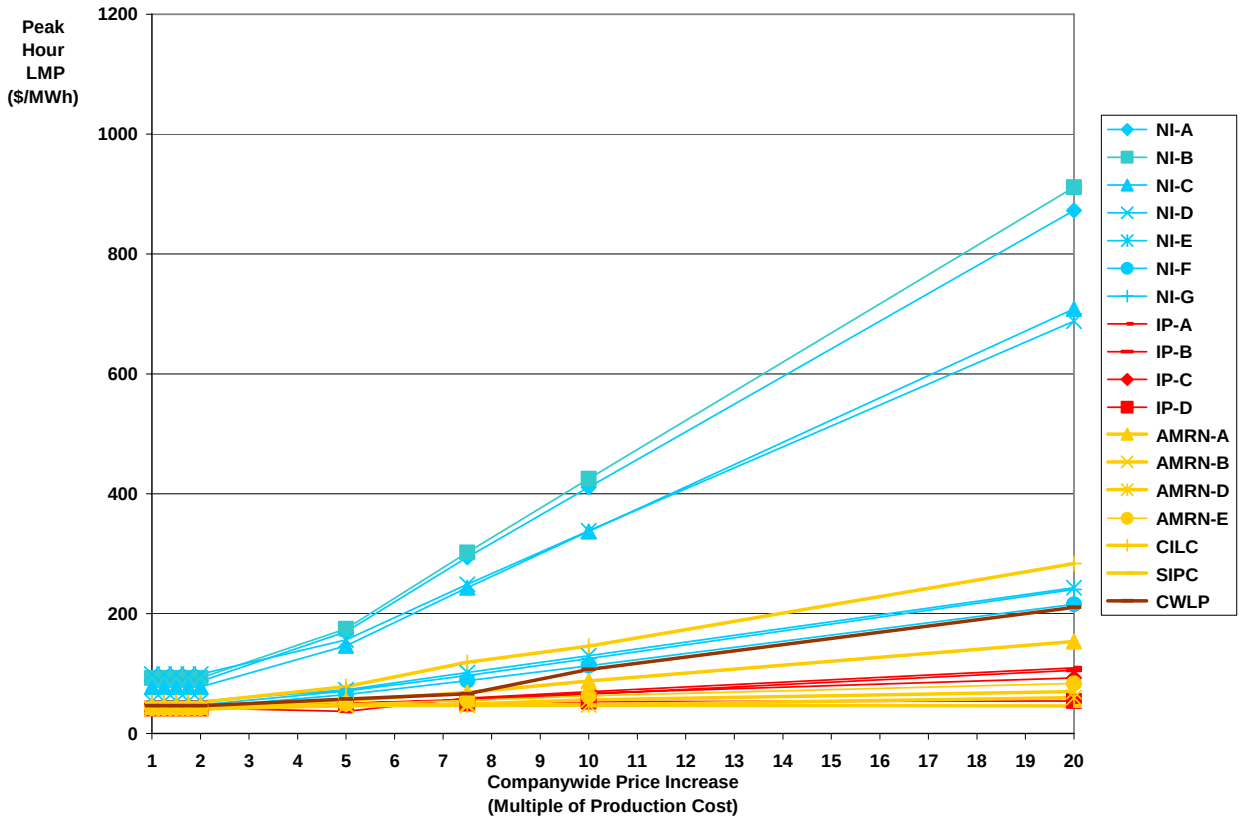

Figure 4.3.2-4 Exelon Nuclear Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

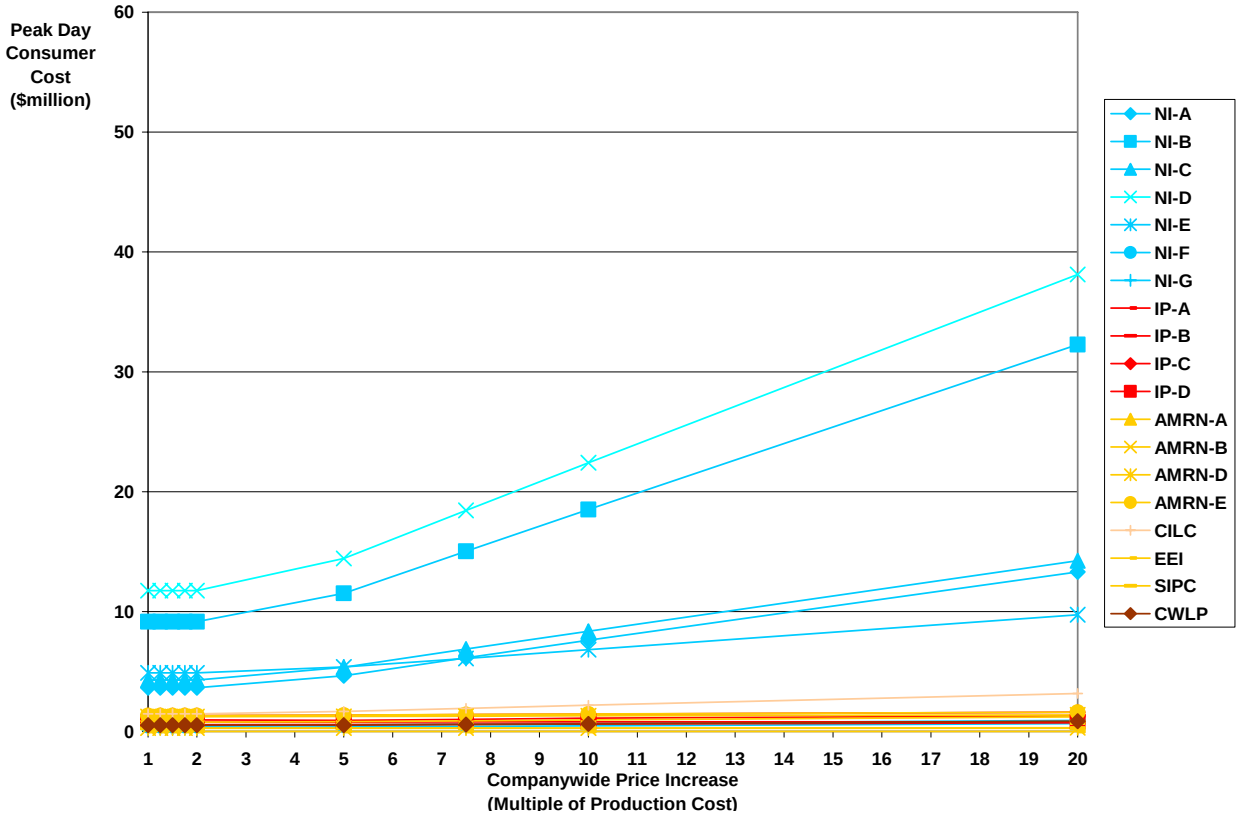

Figure 4.3.2-5 Exelon Nuclear Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-6 shows the effect of the Exelon peak hour price increases using the Conservative Assumptions. Comparing this to Figure 4.3.2-3 shows a somewhat different pattern under these conditions. First, the level of generation by the company is reduced when prices are increased and levels off in the same way it did under the Case Study Assumptions. The company's generation capacity remained competitive, even at 20 times production cost. Recall from the PC cases that the out-of-state suppliers gained market share at the expense of in-state suppliers when moving from Case Study Assumptions to Conservative Assumptions. The results here show that Exelon could still maintain its level of generation at elevated prices under Conservative Assumptions. The limits in the transmission system prevented any other generators from displacing the nuclear units.

The second observation in this result is that the company's profitability did not improve as a result of applying these price increases. Profitability dropped for the initial price increases and grew only slowly after that. This is a result of the much lower market prices seen under the Conservative Assumptions. It takes a much higher price increase to offset even the small amount of generation lost from the price increase. Nevertheless, the trend of the profitability curve indicates that a continuing price increase would, in fact, increase company profitabilty, which is consistent with the trend in the Case Study Assumptions.

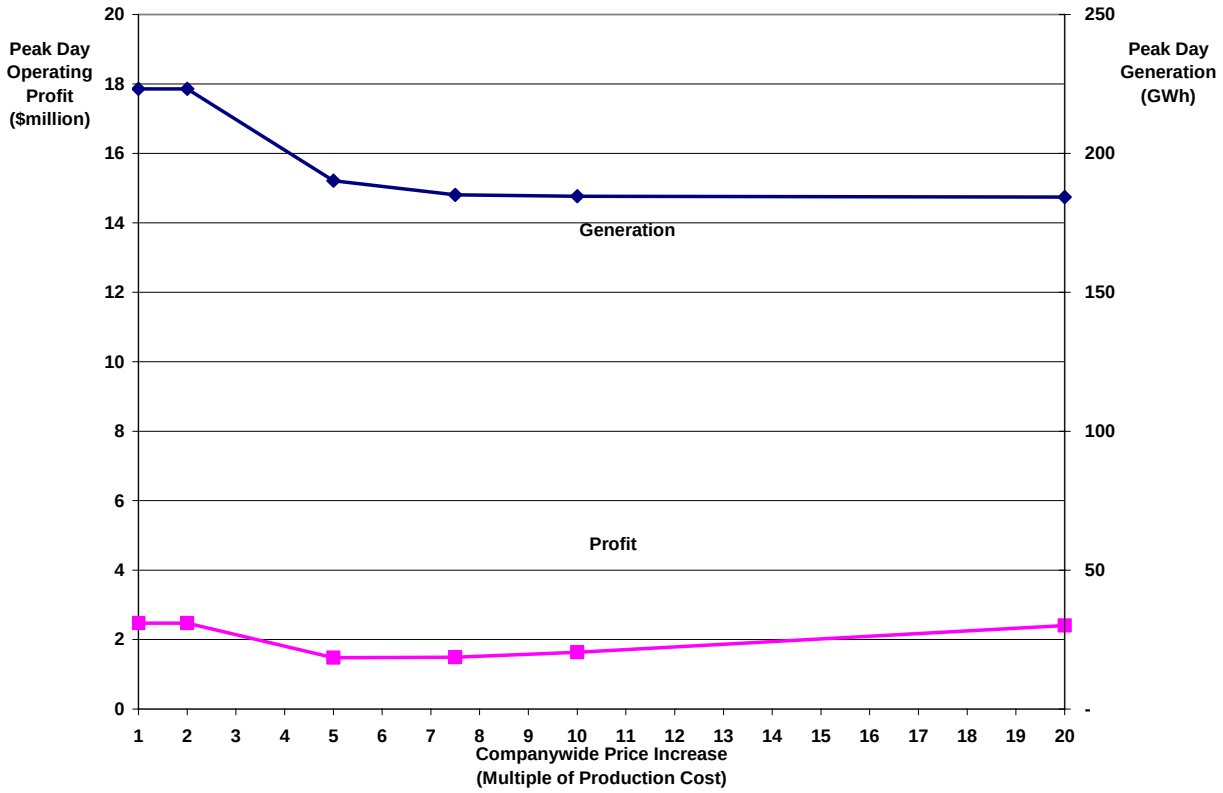

Figure 4.3.2-6 Exelon Nuclear Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-2 shows the transmission components that were at capacity limits at the twenty-fold price increase level under Conservative Assumptions. There was a similar change in the transmission loading as some lines remained at their capacity limits (normal print), some began to experience congestion (bold print), and some saw a relaxation of congestion (shaded print). As was seen in the PC case conditions, the additional generation capacity available under Conservative Assumptions did not eliminate the impacts of transmission congestion. In fact, the additional capacity resulted in more transmission components operating at their limits as the system sought to replace the higher-priced Exelon generation.

Table 4.3.2-2 Transmission Components at Capacity Limits under Exelon Nuclear 20-Fold Peak Hour Price Increase (Conservative Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
36867_37387	**JEFFE; R**	**KINGS; R**	**NI-D**	**NI-D**	**138**	**kV**	**Line**
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line
36271_36415	**B ISL;RT**	**WILTO; R**	**NI-E**	**NI-C**	**345**	**kV**	**Line**
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
36891_37135	**KEWAN;**	**POWER;**	**NI-G**	**NI-G**	**138**	**kV**	**Line**
IP-A							
32411_37135	**PWR JCTB**	**POWER;**	**IP-A**	**NI-G**	**138**	**kV**	**Line**
IP-C							
32355_32369	**PANA IP**	**MOWEAQ T**	**IP-C**	**IP-C**	**138**	**kV**	**Line**
32368_32369	**RT 51 TP**	**MOWEAQ T**	**IP-C**	**IP-C**	**138**	**kV**	**Line**
32388_32405	**SIDNEY**	**MIRA TAP**	**IP-C**	**IP-B**	**138**	**kV**	**Line**
AMRN-B							
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line
30395_31445	**COFFEEN**	**PANA**	**AMRN-B**	**AMRN-B**	**345**	**kV**	**Line**
30439_31351	**CROSSVL**	**NORRIS**	**AMRN-B**	**AMRN-B**	**138**	**kV**	**Line**

Table 4.3.2-2 Transmission Components at Capacity Limits under Exelon Nuclear 20-Fold Peak Hour Price Increase (Conservative Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
AMRN-D							
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	**PICKNYVL**	**PICKVL 5**	**AMRN-E**	**AMRN-E**	**13.8**	**/230**	**Transformer**
31500_31506	**PICKNYVL**	**PICKVL 6**	**AMRN-E**	**AMRN-E**	**13.8**	**/230**	**Transformer**
CILC							
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**
EEI							
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Midwest Generation LLC

Case Study Assumptions

Figure 4.3.2-7 shows the results of companywide economic withholding as applied to the Midwest Generation portfolio of generators. Figure 4.3.2-8 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested. For these simulation runs, the prices were increased for all of the company's units at the same rate for the entire peak day.

The results show that for price increases up to about five times production costs, the company lost generation in the market as cheaper units displaced its higher-priced ones. However, company daily operating profit increased slightly as the higher prices brought in more revenue for those units that were dispatched. As shown in Figure 4.3.2-8, during peak hours about 4,000 MW of the company's generating capacity was needed to meet the peak load. Prices on this capacity could be increased significantly without further loss of generation to competitors and with increasing company profitability. The Crawford, Joliet, Powerton, Waukegan, Will Co., and Fisk plants were dispatched, at least partially, even with the higher prices. Unlike the case for Exelon Nuclear, this dispatch schedule may be able to be accommodated by the company's generating units. Some of the fossil-fueled units have the ability to adjust to follow the load much more readily than the nuclear units. Nevertheless, this may not be a desirable operating schedule because of the extra wear on equipment that is cycled on and off, particularly the larger coal-fired units.

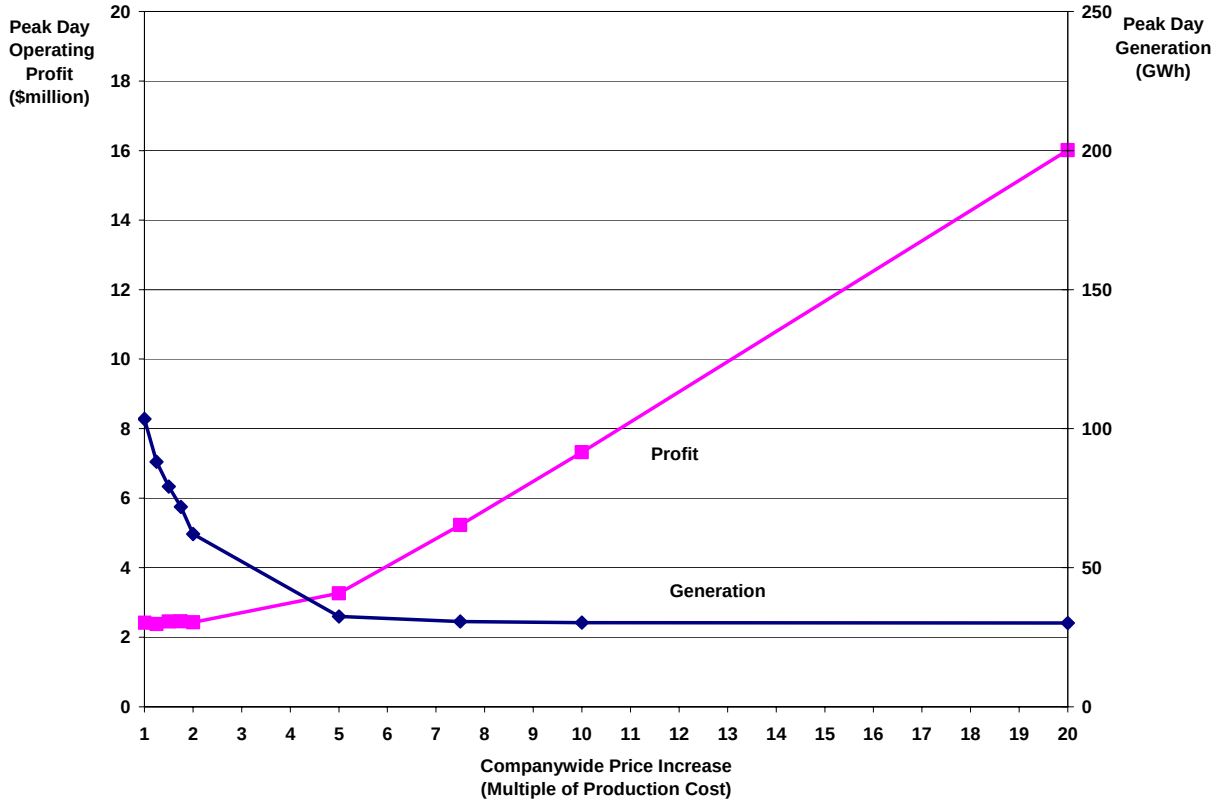

Figure 4.3.2-7 Midwest Generation Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

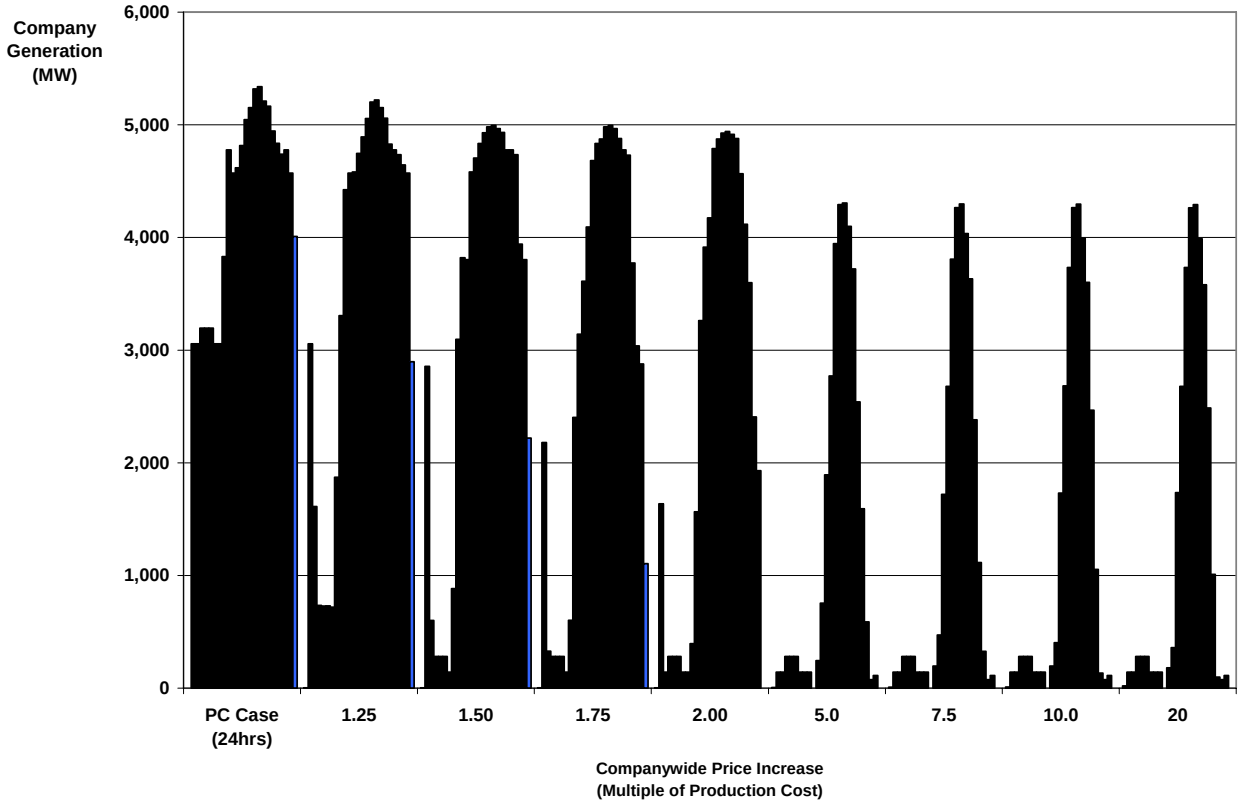

Figure 4.3.2-8 Midwest Generation Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

Figure 4.3.2-9 shows the results of price increases applied only during peak hours. This was a more attractive strategy from the company's perspective. There was very little loss in generation to competitors at any level of price increase. The twenty-fold price increase put the capacity-weighted average of the company's generation at about 630 $/MWh, or about twice the Exelon Nuclear average price at its twenty-fold increase. The company's generation was still accepted by the market at these very high prices because of transmission constraints that prohibited cheaper power from being utilized. Table 4.3.2-3 shows the transmission components that were at capacity limits under the twenty-fold price increase. This list is similar to what was seen for the Exelon Nuclear price increases. The differences in line loadings result from the locations on the transmission network of the Midwest Generation plants relative to the Exelon Nuclear plants. Note that there was no relaxation of congestion anywhere in the system under these conditions.

Figure 4.3.2-10 shows the impact of the price increments on zonal LMPs. Figure 4.3.2-11 shows the impact on consumer costs. The results are similar to those for Exelon Nuclear. The company had a significant impact, particularly in the NI zones, because of the transmission limits. There was also an impact in the CILC zone, which was affected by transmission constraints. As before, this should not be interpreted as an indication that the company would, in practice, exercise this market power. It only indicates that this could be a profitable strategy.

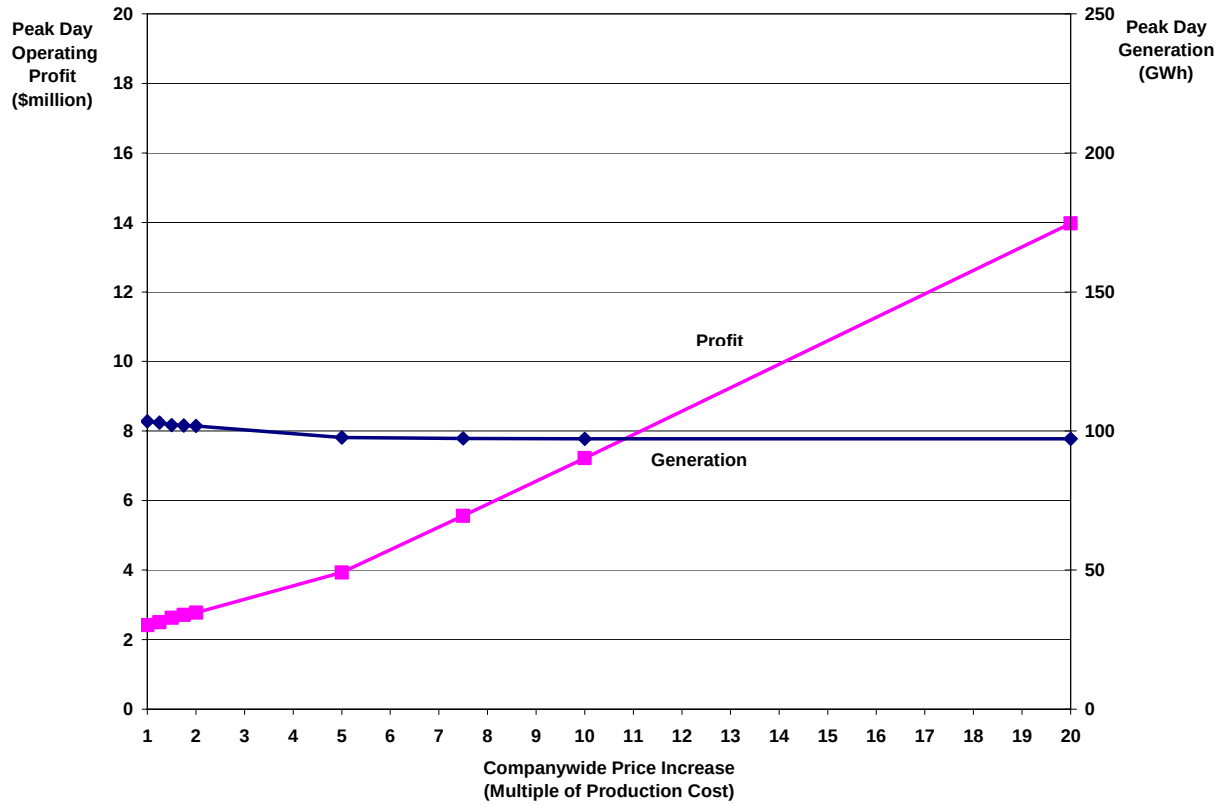

Figure 4.3.2-9 Midwest Generation Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-3 Transmission Components at Capacity Limits under Midwest Generation 20-Fold Price Increase (Case Study Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36766_37372	**FRONT; B**	**WOLFS; B**	**NI-C**	**NI-C**	**138**	**kV**	**Line**
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36295_36022	**CRAWF; R**	**CRAWF;1M**	**NI-D**	**NI-D**	**138**	**/345**	**Transformer**
36022_36641	**CRAWF;1M**	**CRAWF; R**	**NI-D**	**NI-D**	**138**	**/138**	**Transformer**
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36271_36415	**B ISL;RT**	**WILTO; R**	**NI-E**	**NI-C**	**345**	**kV**	**Line**
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-B							
32410_33159	**1346A TP**	**KICKAPOO**	**IP-B**	**CILC**	**138**	**kV**	**Line**
32358_32410	**LATH NTP**	**1346A TP**	**IP-B**	**IP-B**	**138**	**kV**	**Line**
AMRN-A							
30055_33315	**AUBURN N**	**CHATHAM**	**AMRN-A**	**CWLP**	**138**	**kV**	**Line**
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer
CILC							
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**
CWLP							
33314_33315	**SPALDING**	**CHATHAM**	**CWLP**	**CWLP**	**138**	**kV**	**Line**

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

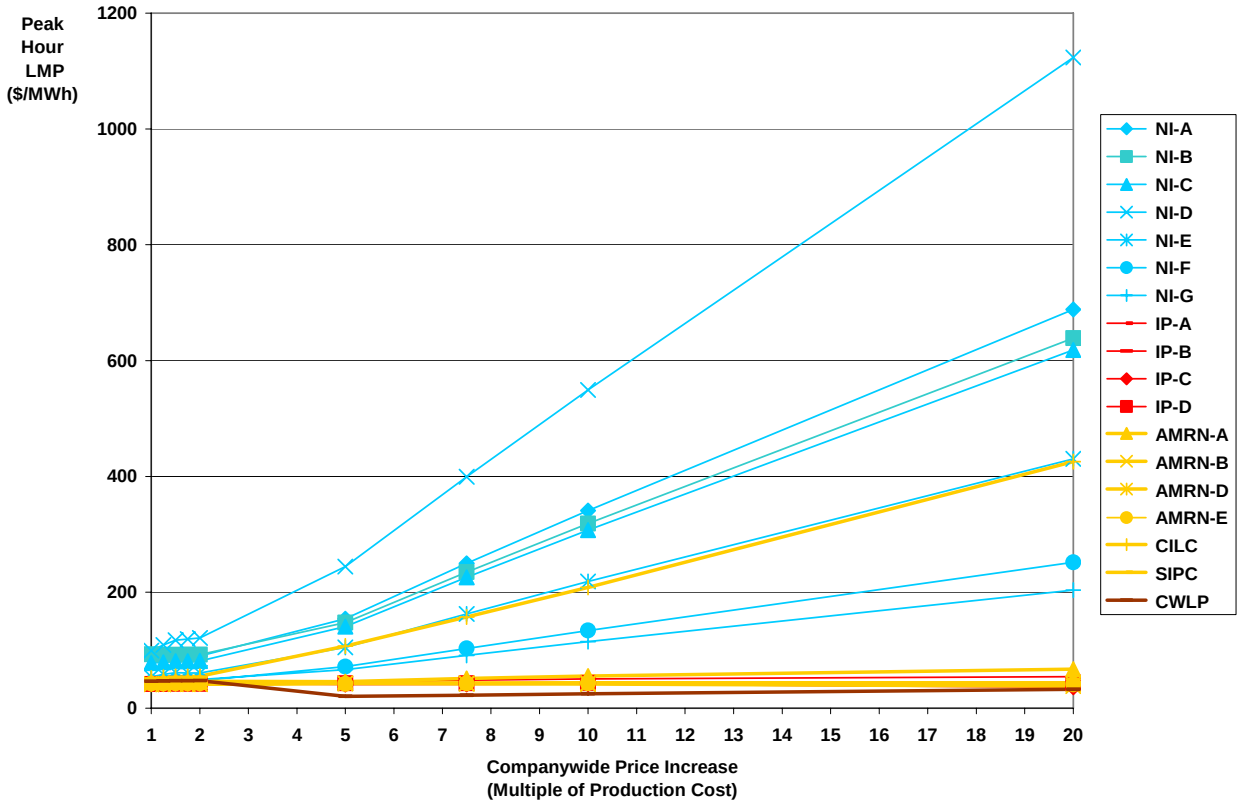

Figure 4.3.2-10 Midwest Generation Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

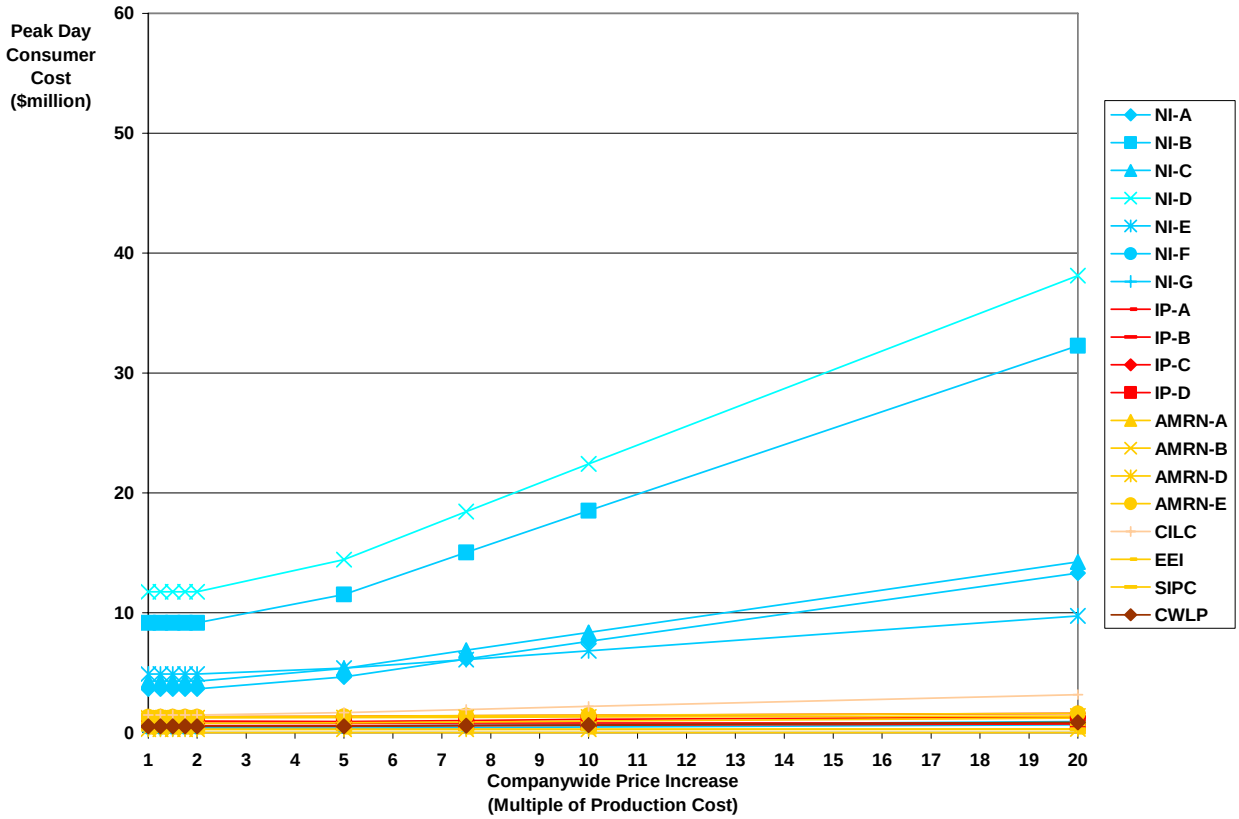

Figure 4.3.2-11 Midwest Generation Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-12 shows the company's generation and operating profit under Conservative Assumptions. The pattern is very similar to the results from the Case Study Assumptions. That is, there was very little loss of generation, even at large price increases. There was a continuing increase in operating profits with continued price increases. As in the Exelon Nuclear case, the rate of profitability increase was slower than under Case Study Assumptions due to the lower overall market prices under these conditions. Table 4.3.2-4 shows the transmission components at their operating limits. It is again similar to what was seen for Exelon Nuclear.

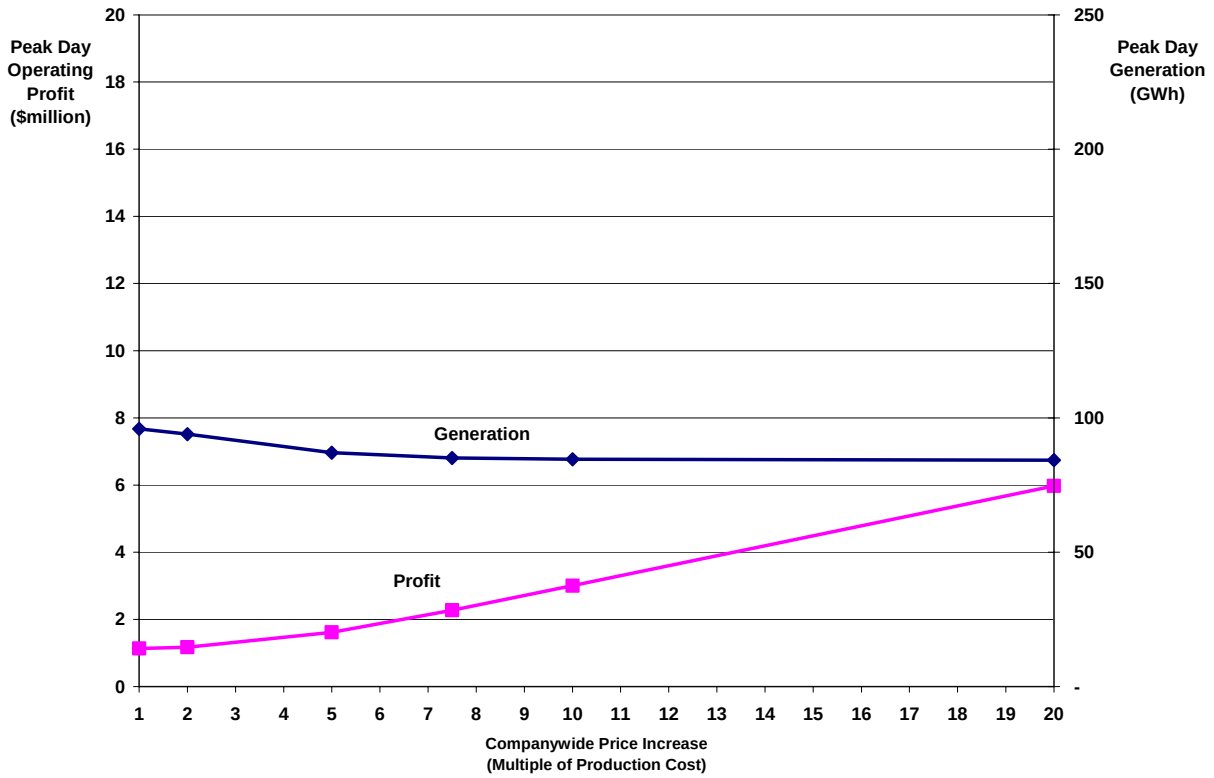

Figure 4.3.2-12 Midwest Generation Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-4 Transmission Components at Capacity Limits under Midwest Generation 20-Fold Price Increase (Conservative Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36766_37372	**FRONT; B**	**WOLFS; B**	**NI-C**	**NI-C**	**138**	**kV**	**Line**
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-B							
32410_33159	**1346A TP**	**KICKAPOO**	**IP-B**	**CILC**	**138**	**kV**	**Line**
32358_32410	**LATH NTP**	**1346A TP**	**IP-B**	**IP-B**	**138**	**kV**	**Line**
IP-C							
32388_32405	**SIDNEY**	**MIRA TAP**	**IP-C**	**IP-B**	**138**	**kV**	**Line**
AMRN-A							
30055_33315	**AUBURN N**	**CHATHAM**	**AMRN-A**	**CWLP**	**138**	**kV**	**Line**
AMRN-B							
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line
AMRN-D							
30614_30615	**GIBSON C**	**GIBSONCP**	**AMRN-D**	**AMRN-D**	**138**	**kV**	**Line**
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
CILC							
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**
EEI							
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line
CWLP							
33314_33315	**SPALDING**	**CHATHAM**	**CWLP**	**CWLP**	**138**	**kV**	**Line**

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Ameren

Case Study Assumptions

Figure 4.3.2-13 shows the results of companywide economic withholding as applied to the Ameren portfolio of generators. Figure 4.3.2-14 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested. For these simulation runs, the prices were increased for all of the company's units at the same rate for the entire peak day.

The results show that the company lost both generation and profitability using this strategy. Even at large increases in prices, the profitability did not return to the PC case level. Competitors, both in-state and out-of-state, were able to supplant the company's higher-priced units. As shown in Figure 4.3.2-14, during peak hours about 500 MW of the company's capacity was needed to meet the peak load, even with high prices.

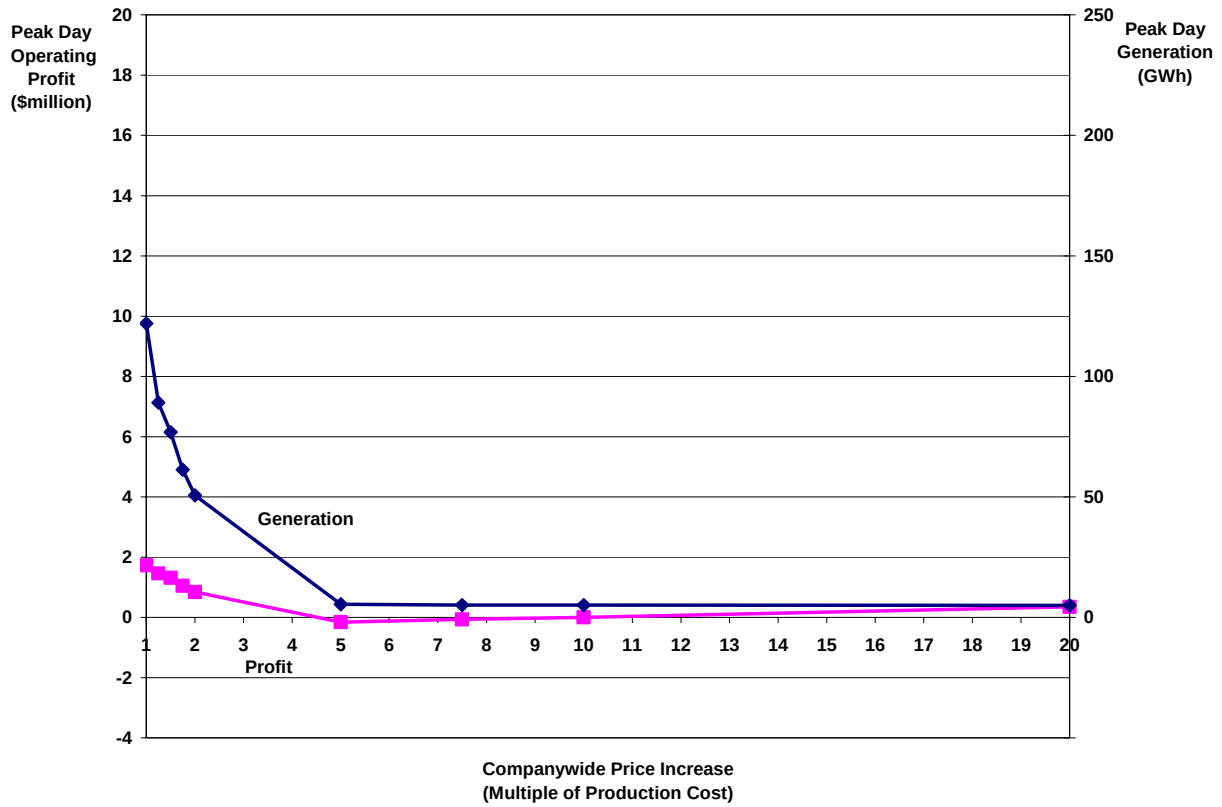

Figure 4.3.2-13 Ameren Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

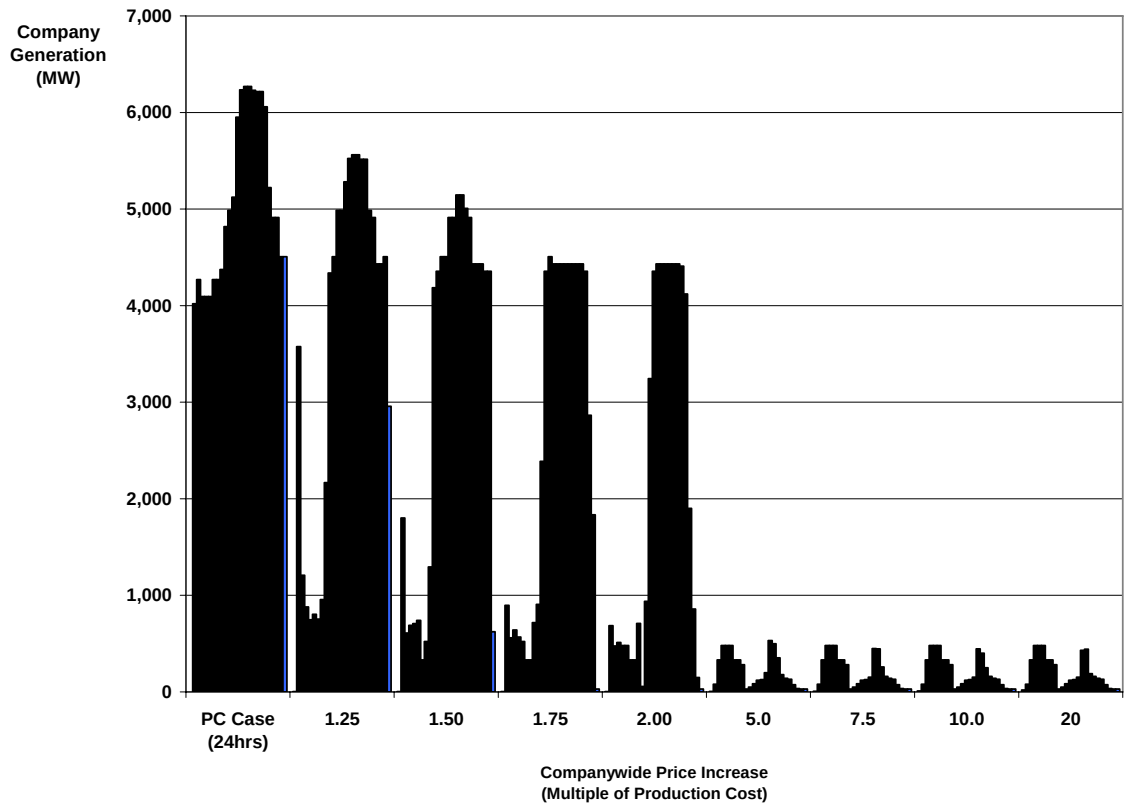

Figure 4.3.2-14 Ameren Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

Figure 4.3.2-15 shows the results of price increases applied only during peak hours. This strategy did not offer any benefit to the company even after a significant increase. (At a twenty-fold price increase, the capacity-weighted average of the company's generation was about 470 $/MWh.) The reason for this small impact is that the company's units were not as critical to meeting system loads as were those of Exelon Nuclear and Midwest Generation. Only the E.D. Ewards and Elgin Energy Center units continued to be dispatched at these high prices. There was ample generation and transmission capacity available to displace the company's units when their prices were increased. Table 4.3.2-5 shows the transmission components that were at capacity limits under the twenty-fold price increase. Several components experienced congestion as the system was redispatched to replace the more expensive Ameren units, but this did not result in any profit increases for the company.

Figure 4.3.2-16 shows the effect on zonal LMPs. Figure 4.3.2-17 shows the effect on consumer costs. Note that while the price increases by the company did not provide increased profitability, they did have a significant impact on the system across parts of the State. As in the Exelon and Midwest Generation results, the NI zones and the CILC zone were most affected because of their transmission constraints. The Ameren price increase did not create any new congestion within the NI zones; nevertheless, the congestion created elsewhere caused significant impacts there.

In effect, if the company increased its prices, the primary beneficiaries would be other companies. As the company increased prices on its units, it allowed other companies' units, which would not have been dispatched under PC case conditions, to be selected. These units, although cheaper than the Ameren units whose prices had been increased, were still more expensive than those that were used in the PC case. Thus all companies benefited from the higher price in the market.

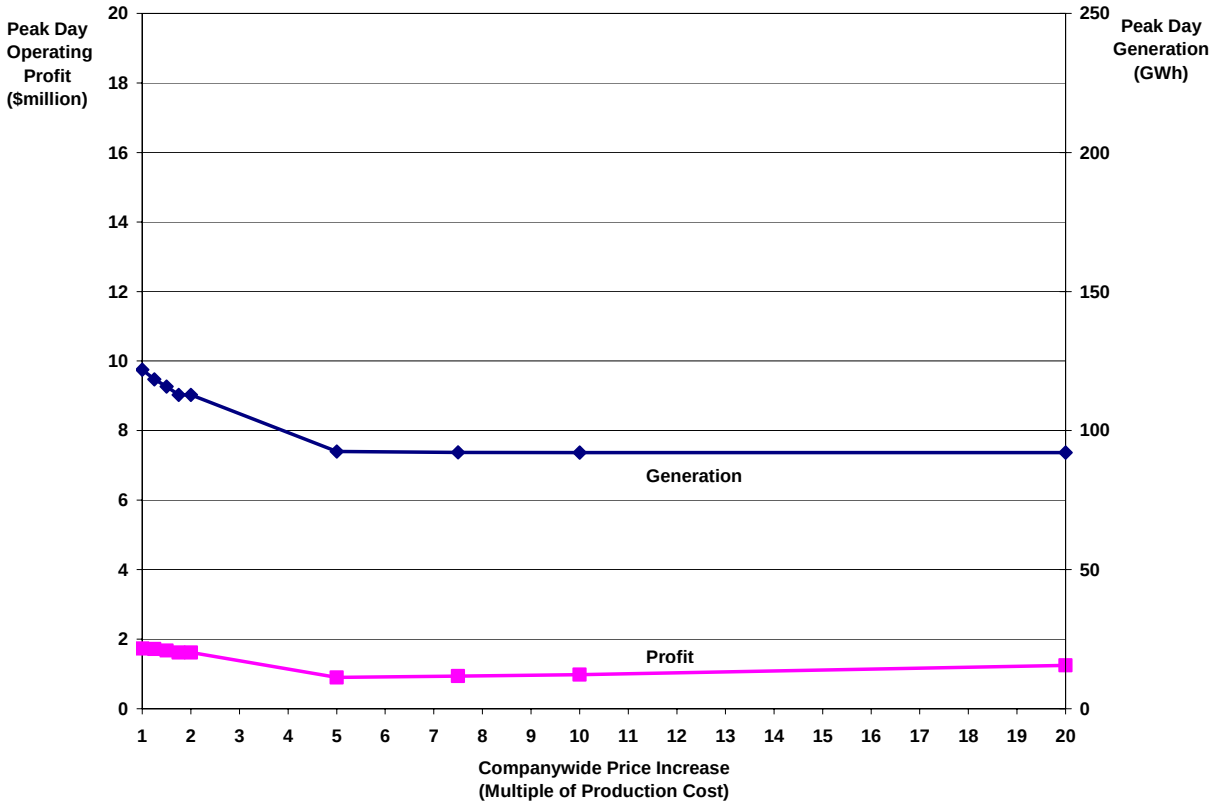

Figure 4.3.2-15 Ameren Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-5 Transmission Components at Capacity Limits under Ameren 20-Fold Price Increase (Case Study Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-B							
32358_32410	**LATH NTP**	**1346A TP**	**IP-B**	**IP-B**	**138**	**kV**	**Line**
32410_33159	**1346A TP**	**KICKAPOO**	**IP-B**	**CILC**	**138**	**kV**	**Line**
AMRN-A							
30055_33315	**AUBURN N**	**CHATHAM**	**AMRN-A**	**CWLP**	**138**	**kV**	**Line**
AMRN-B							
30439_31351	**CROSSVL**	**NORRIS**	**AMRN-B**	**AMRN-B**	**138**	**kV**	**Line**
31350_31351	**NORRIS**	**NORRIS**	**AMRN-B**	**AMRN-B**	**138**	**/345**	**Transformer**
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer
CILC							
33002_33139	**RS WALL**	**RSW EAST**	**CILC**	**CILC**	**138**	**/69**	**Transformer**
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

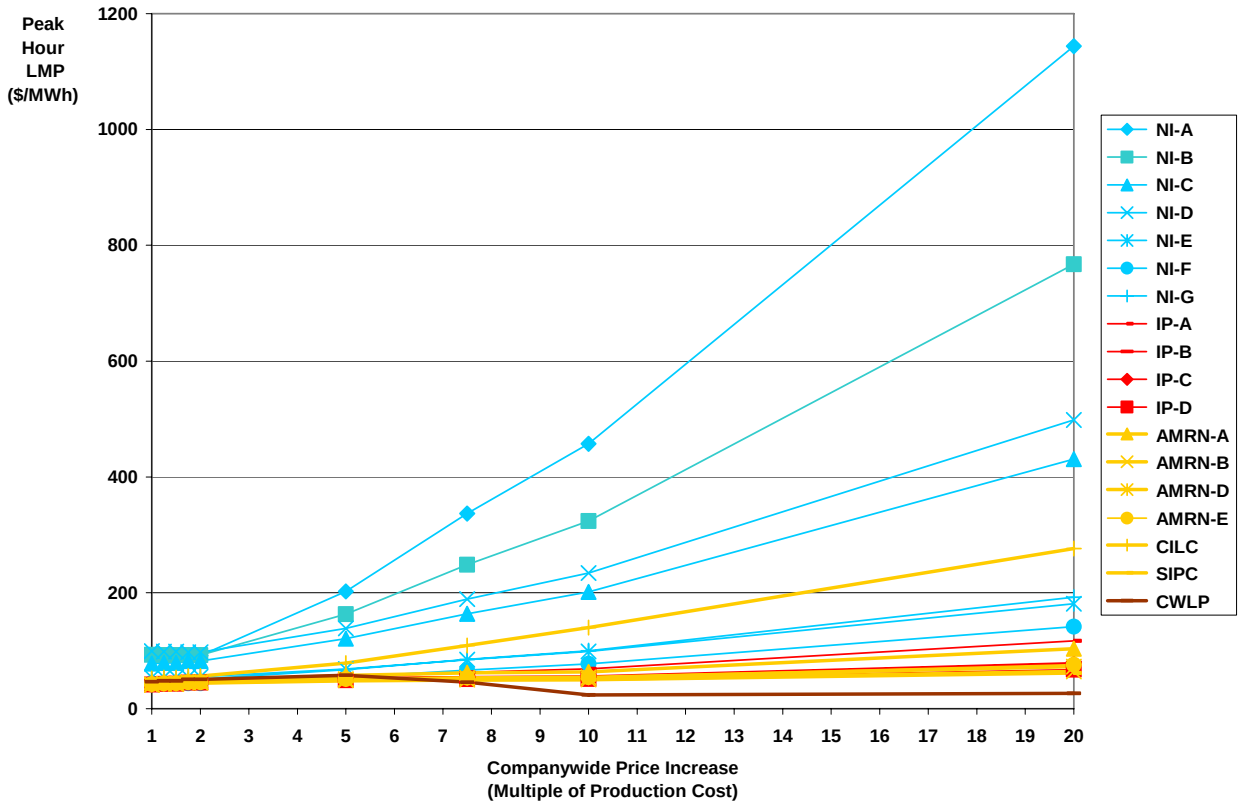

Figure 4.3.2-16 Ameren Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

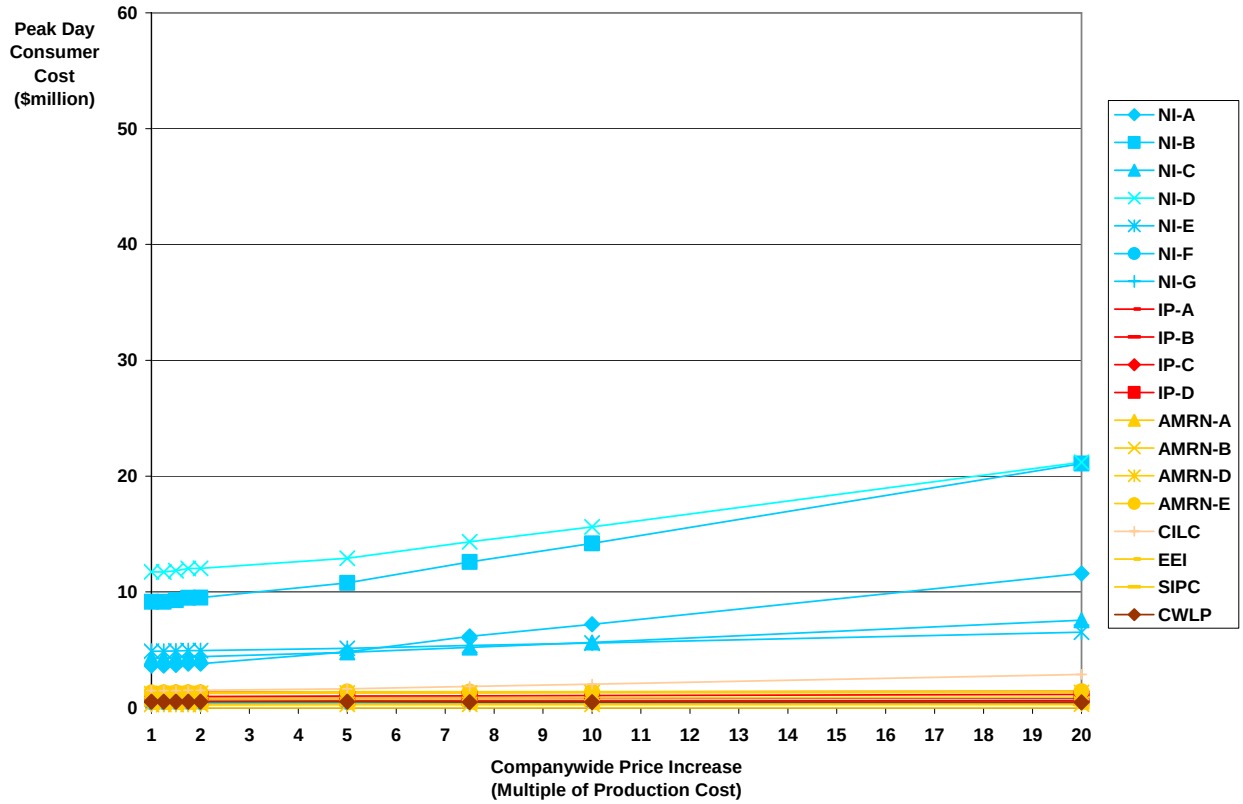

Figure 4.3.2-17 Ameren Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-18 shows the effect on company generation and operating profits under Conservative Assumptions. The result was essentially the same as under Case Study Assumptions. That is, there was no profit benefit to the company from unilateral price increases. Table 4.3.2-6 shows the transmission components that were at their capacity limits. Some components experienced additional congestion, but, as before, this did not result in any profit increases for the company.

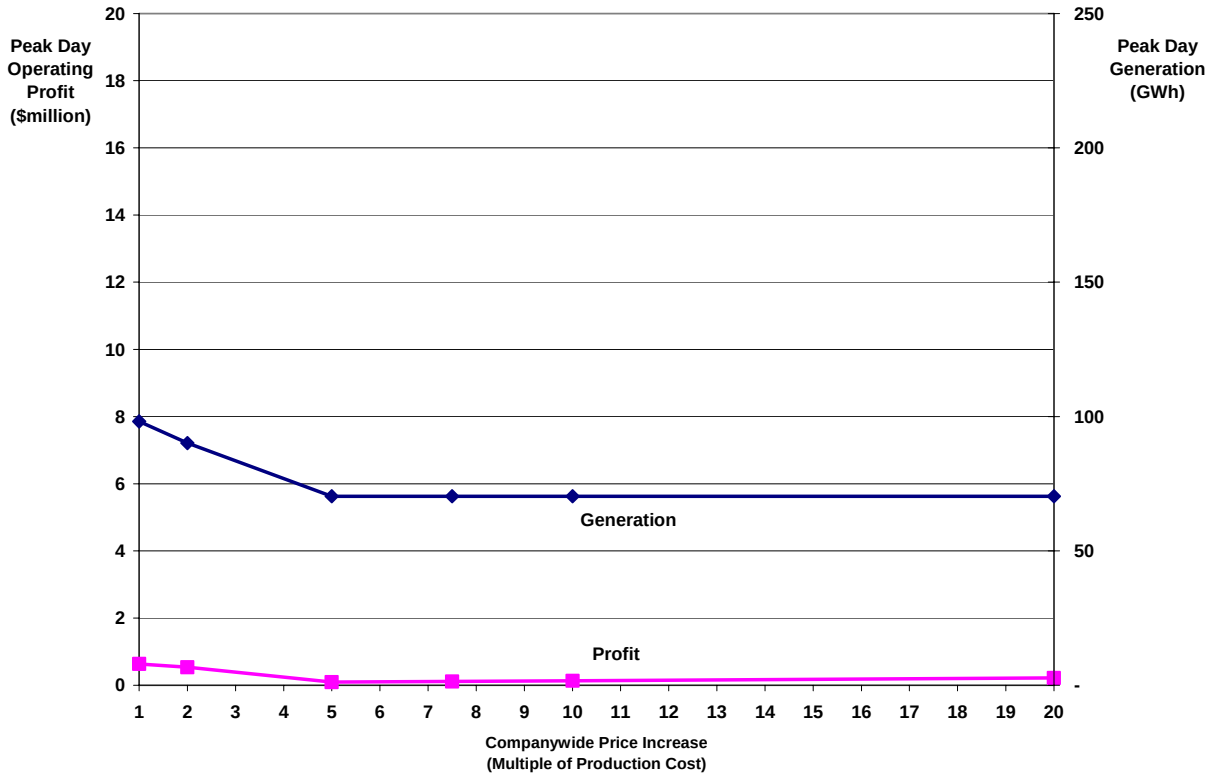

Figure 4.3.2-18 Ameren Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-6 Transmission Components at Capacity Limits under Ameren 20-Fold Price Increase (Conservative Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36867_37387	**JEFFE; R**	**KINGS; R**	**NI-D**	**NI-D**			
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-B							
32410_33159	**1346A TP**	**KICKAPOO**	**IP-B**	**CILC**			
AMRN-B							
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line
AMRN-D							
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line
AMRN-E							
31023_33351	**MARION S**	**5MRN_PLN**	**AMRN-E**	**SIPC**			
CILC							
33002_33139	**RS WALL**	**RSW EAST**	**CILC**	**CILC**			
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**			
EEI							
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Dynegy

Case Study Assumptions

Figure 4.3.2-19 shows the results of companywide economic withholding as applied to the Dynegy portfolio of generators. Figure 4.3.2-20 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested. For these simulation runs, the prices were increased for all of the company's units at the same rate for the entire peak day.

The results show that the company lost both generation and profits at any price increase. At increase multiples of five or more, the company's units were not dispatched and operating profit became negative as fixed costs could not be recovered. Cheaper units replaced almost all of the company's capacity, even during peak-load periods. At the twenty-fold price increase, the company's capacity-weighted average bid price was about 470 $/MWh.

Figure 4.3.2-21 shows the results of price increases applied only during peak hours. The situation was not much better for the company. A smaller drop in generation was seen, but profitability was still below PC case levels. Table 4.3.2-7 shows the transmission components that were at their capacity limits under the twenty-fold price increase. There was little change from the PC case conditions.

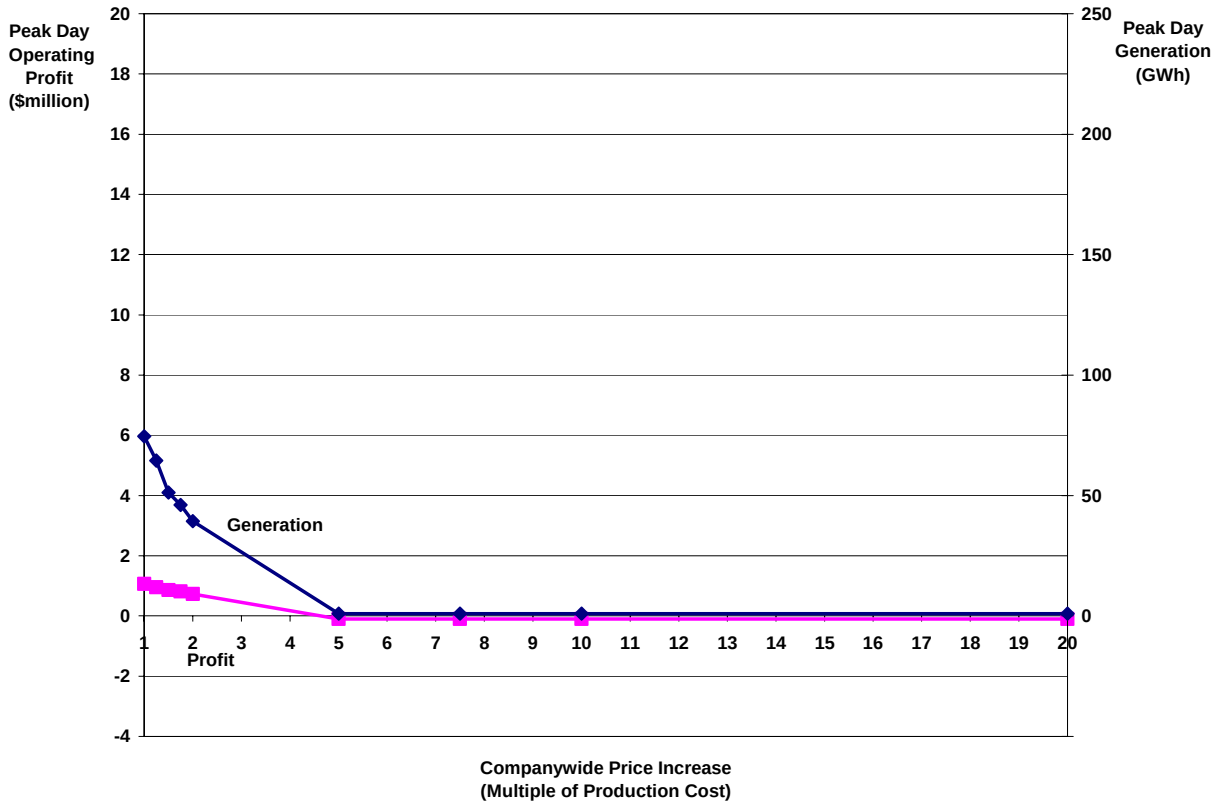

Figure 4.3.2-19 Dynegy Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

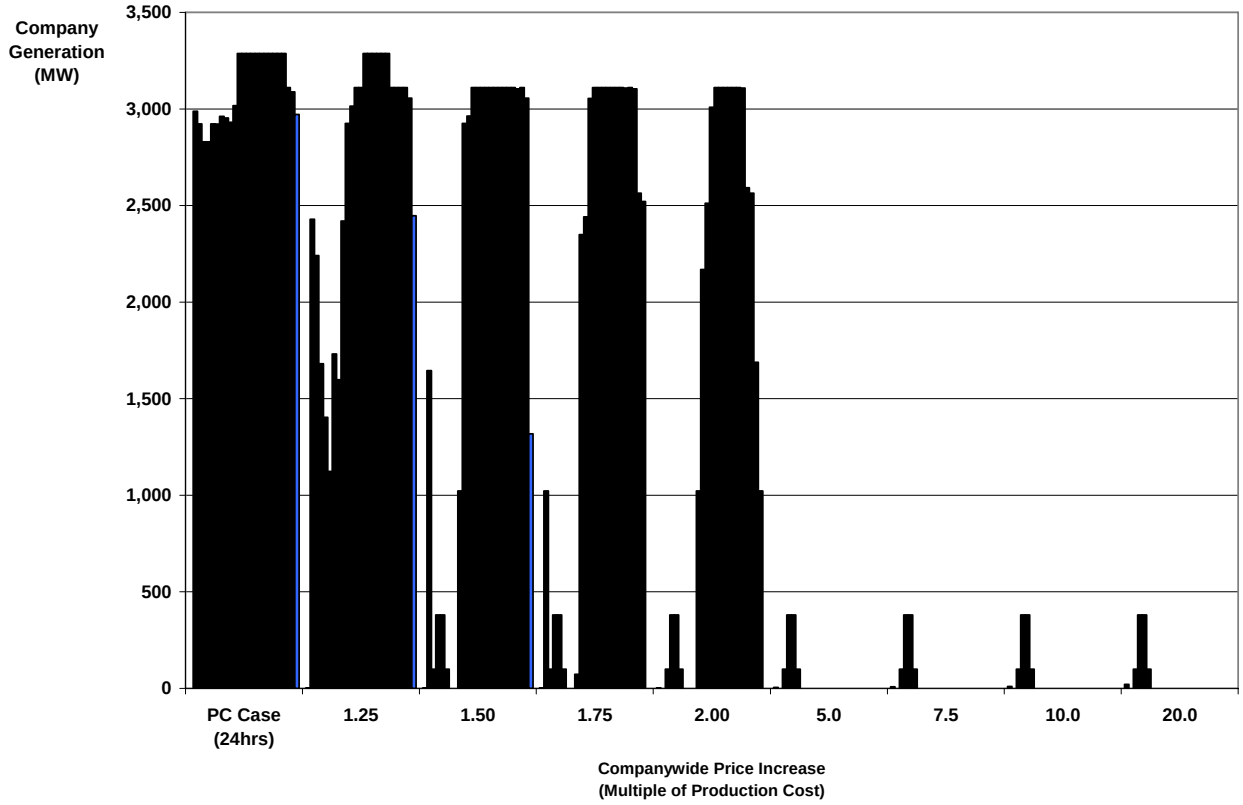

Figure 4.3.2-20 Dynegy Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

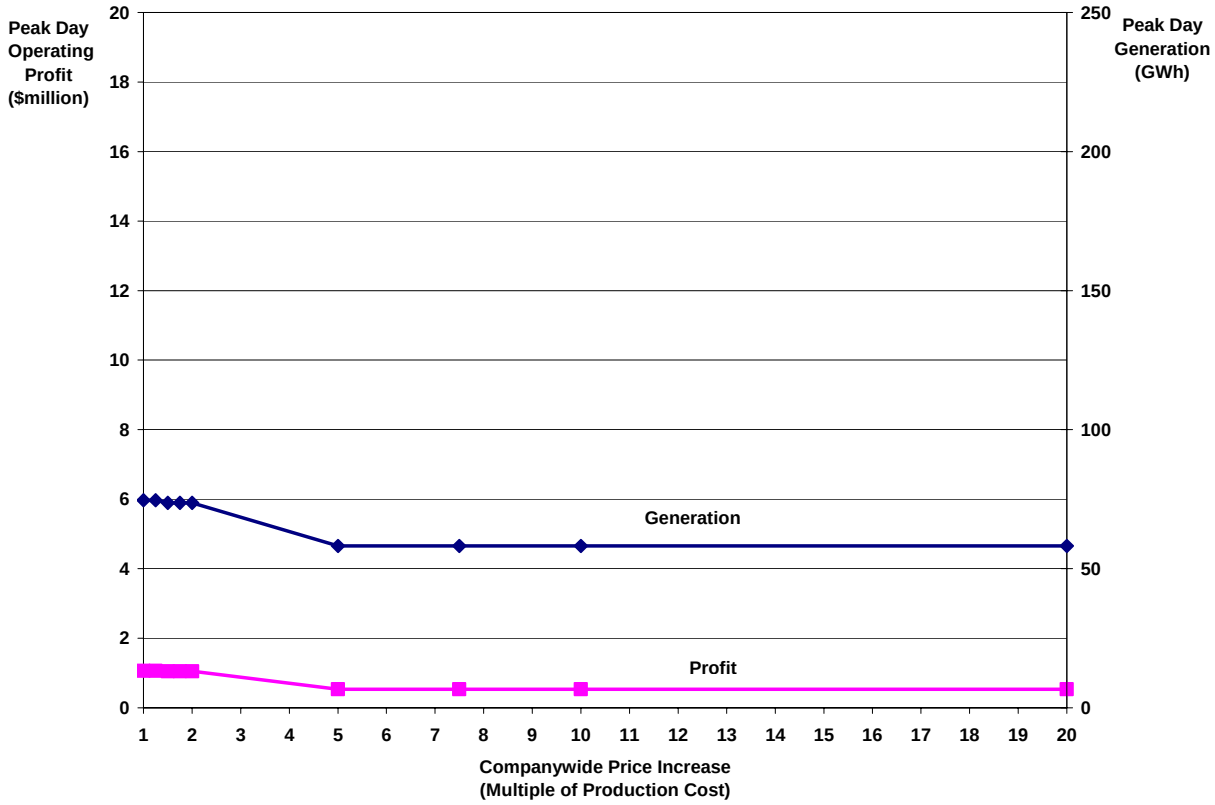

Figure 4.3.2-21 Dynegy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-7 Transmission Components at Capacity Limits under Dynegy 20-Fold Price Increase (Case Study Assumptions)

ID	Bus		Zone		Equipment	
	From	To	From	To		
NI-A						
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138 kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138 kV	Line
NI-C						
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345 kV	Line
36310_36356	**ELECT; B**	**LOMBA; B**	**NI-C**	**NI-C**	**345 kV**	**Line**
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138 kV	Line
NI-D						
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138 kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138 kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138 kV	Line
NI-E						
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138 /345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138 /138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345 kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138 kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345 kV	Line
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138 kV	Line
36702_36754	**E FRA; B**	**FFORT; B**	**NI-E**	**NI-E**	**138 kV**	**Line**
NI-G						
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138 kV	Line
AMRN-D						
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138 kV	Line
AMRN-E						
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8 /230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8 /230	Transformer

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

Figure 4.3.2-22 shows the effect on zonal LMPs. Figure 4.3.2-23 shows the effect on consumer costs. The company's price increases had very little effect on either LMPs or consumer costs. There was adequate generation and transmission capacity available to displace the company's units when their prices were increased. On this basis, there is no indication of the ability to exercise market power.

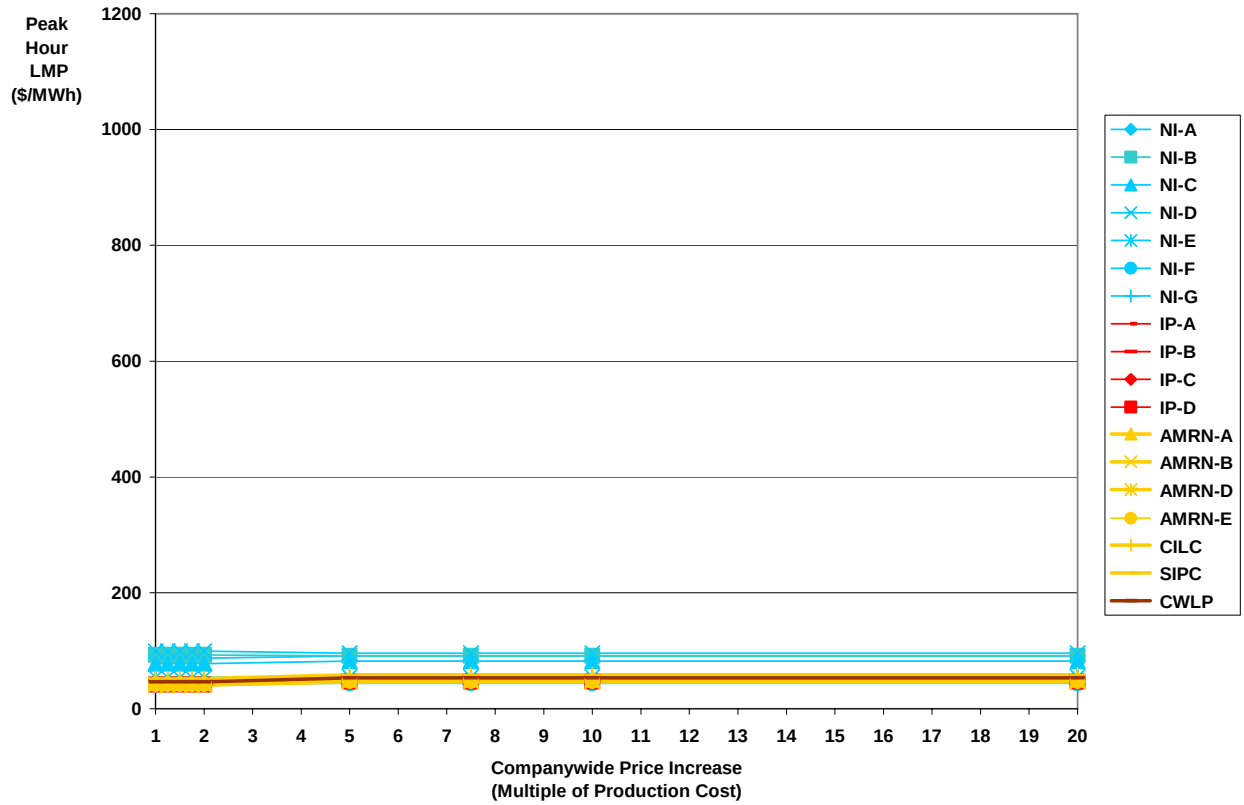

Figure 4.3.2-22 Dynegy Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

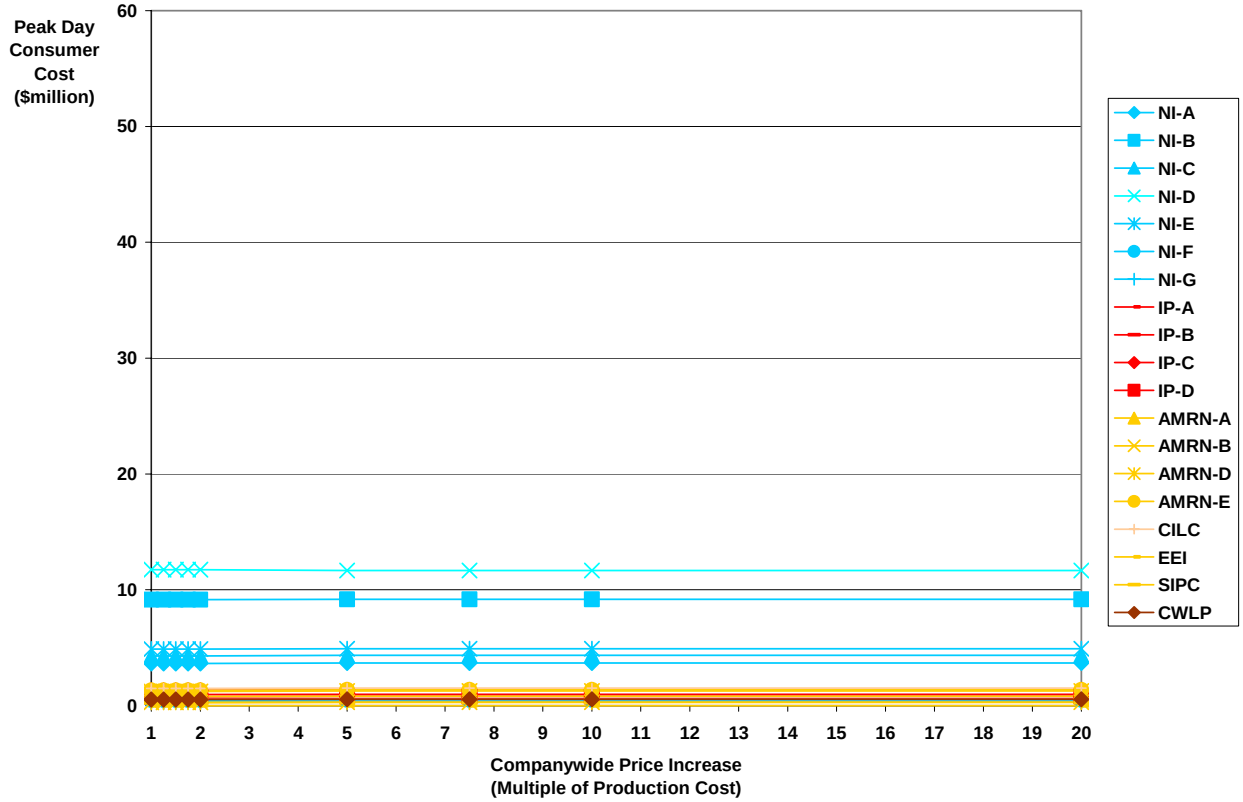

Figure 4.3.2-23 Dynegy Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-24 shows the generation and operating profit under Conservative Assumptions. The pattern was the same as for the Case Study Assumptions. Table 4.3.2-8 shows the transmission components at capacity limits. There was a change in the transmission loading, with some components experiencing increased congestion and some seeing a relaxation of congestion. However, this did not affect company profitability.

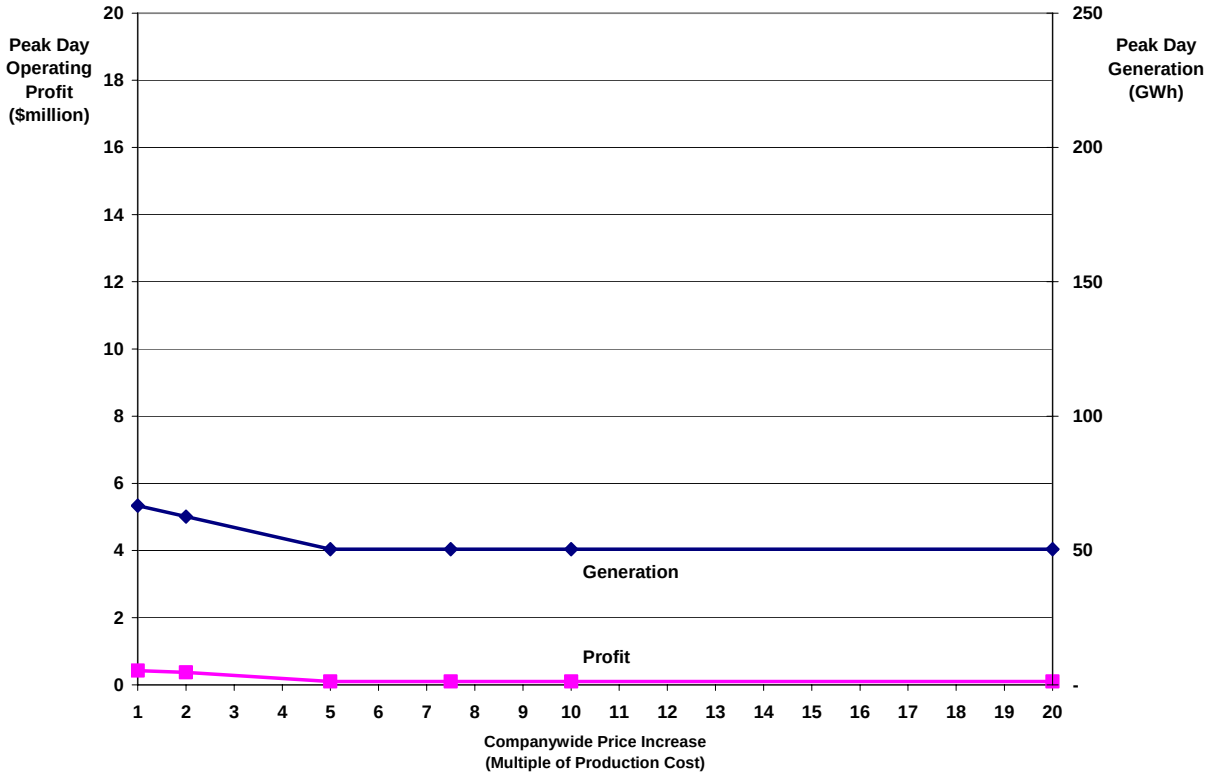

Figure 4.3.2-24 Dynegy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-8 Transmission Components at Capacity Limits under Dynegy 20-Fold Price Increase (Conservative Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-C							
32388_32405	**SIDNEY**	**MIRA TAP**	**IP-C**	**IP-B**	**138**	**kV**	**Line**
IP-D							
32293_32320	**CAMBL TP**	**STEELVIL**	**IP-D**	**IP-D**	**138**	**kV**	**Line**
AMRN-B							
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line
AMRN-D							
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line
30614_30615	**GIBSON C**	**GIBSONCP**	**AMRN-D**	**AMRN-D**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	**PICKNYVL**	**PICKVL 5**	**AMRN-E**	**AMRN-C**	**13.8**	**/230**	**Transformer**
31500_31506	**PICKNYVL**	**PICKVL 6**	**AMRN-E**	**AMRN-C**	**13.8**	**/230**	**Transformer**
EEI							
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Dominion Energy

Case Study Assumptions

Figure 4.3.2-25 shows the results of companywide economic withholding as applied to the Dominion Energy portfolio of generators. Figure 4.3.2-26 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested. For these simulation runs, the prices were increased for all of the company's units at the same rate for the entire peak day.

The results show that the company lost both generation and profitability using this strategy, even at twenty-fold price increases. At this level, the company's capacity-weighted average bid price was about 485 $/MWh. Some of the company's capacity was needed during peak hours, but this became less attractive at higher prices. There was capacity available to replace units that were priced very high.

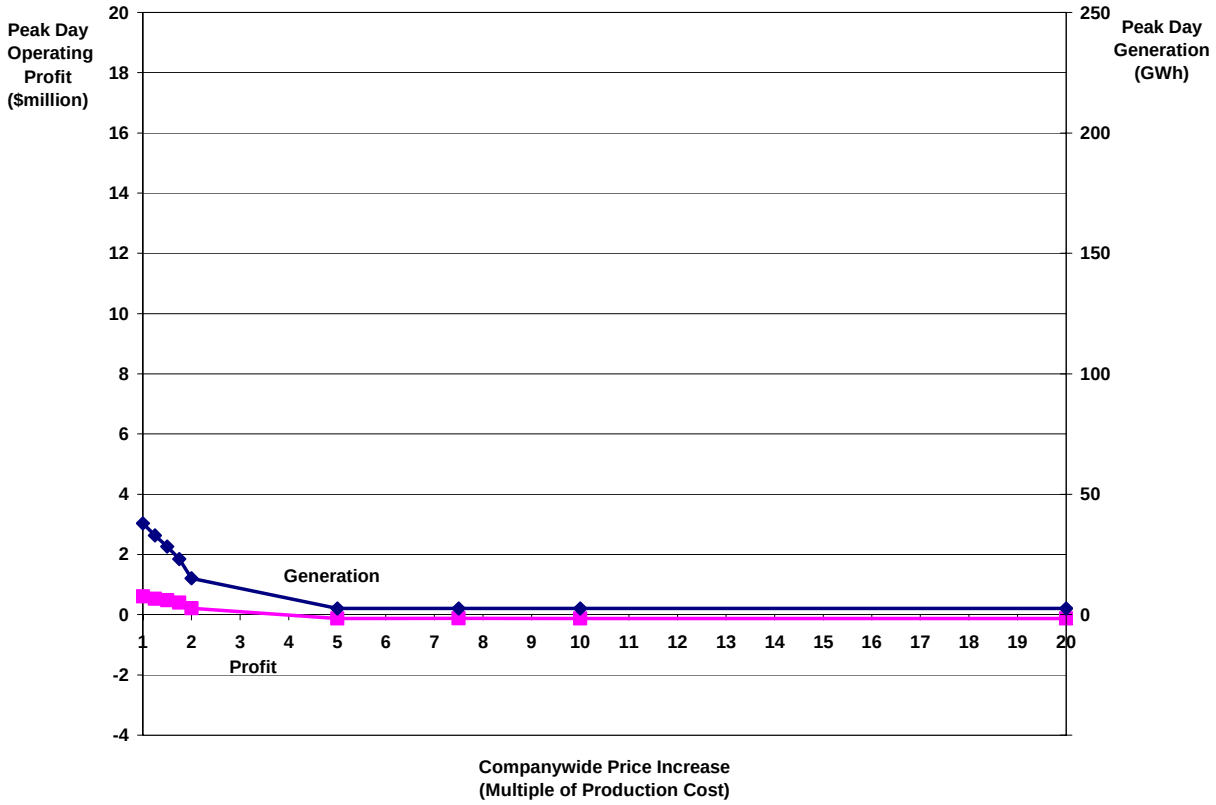

Figure 4.3.2-25 Dominion Energy Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

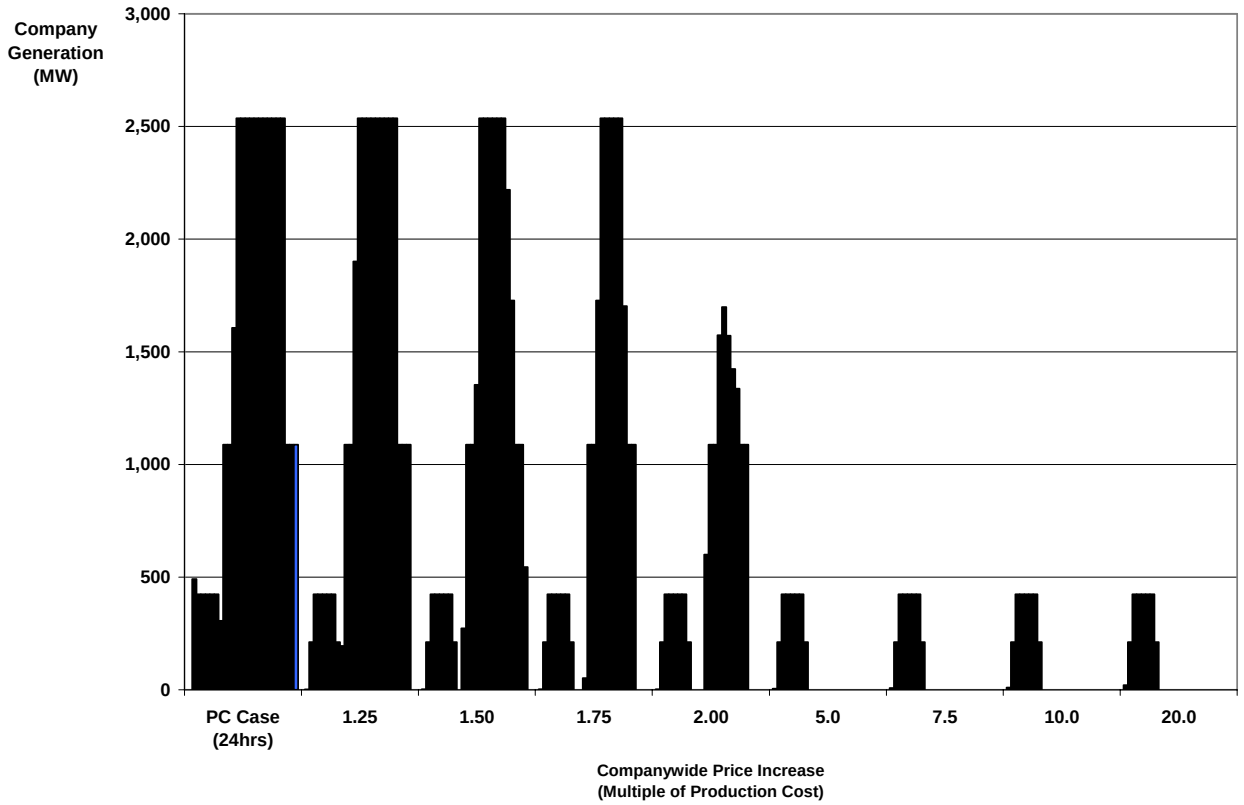

Figure 4.3.2-26 Dominion Energy Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

Figure 4.3.2-27 shows the results of price increases applied only during peak hours. There was not much improvement for the company in this strategy. Profitability was increased only slightly at the high price increases, but was still below PC case levels. As was seen earlier, there was adequate generation and transmission capacity available to displace the company's units when their prices were increased. Table 4.3.2-9 shows the transmission components that were at capacity limits under these conditions. There were some changes in the transmission congestion, but this did not enable the company to increase its profitability. On this basis, there was no indication of the company's ability to exercise market power.

Figure 4.3.2-28 shows the effect on zonal LMPs. Figure 4.3.2-29 shows the effect on consumer costs. While the price increases by the company did not provide much in the way of increased profitability, they did have some impact on the system across parts of the State, particularly in the NI zones. In effect, if the company increased its prices, the primary beneficiaries would be other companies.

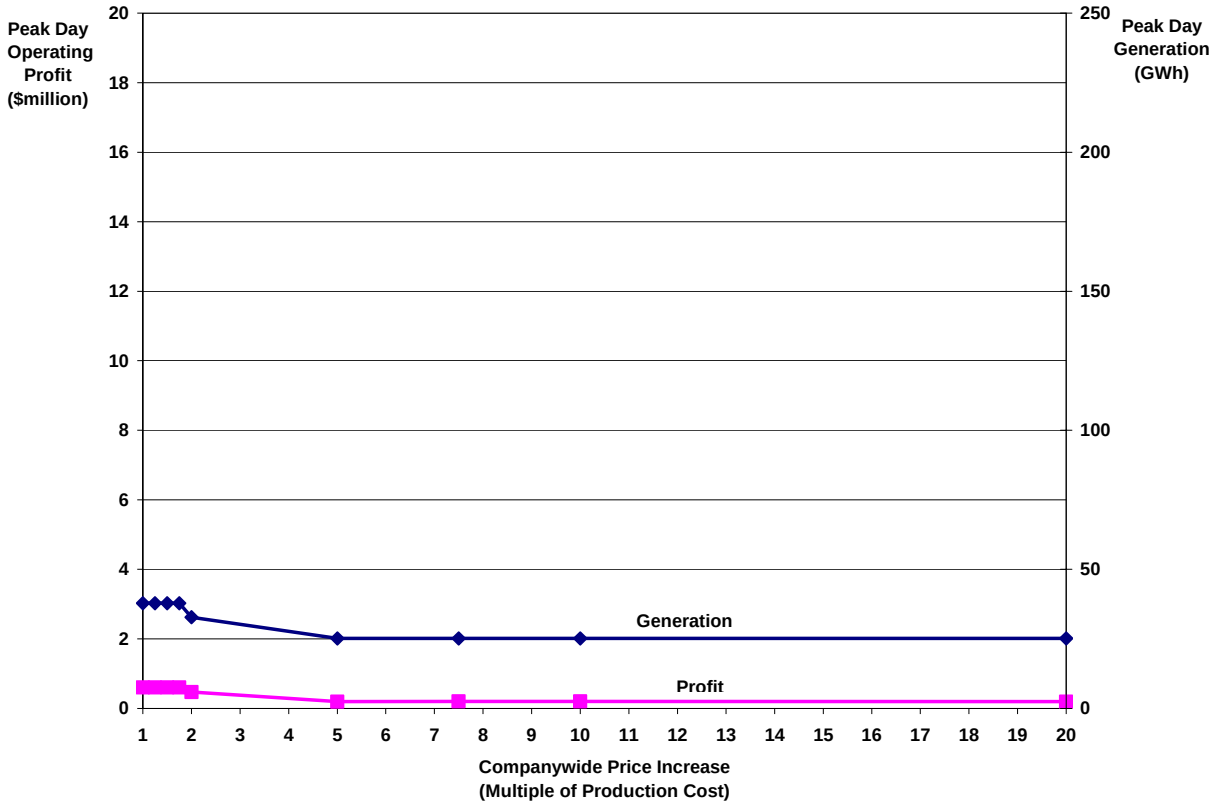

Figure 4.3.2-27 Dominion Energy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-9 Transmission Components at Capacity Limits under Dominion Energy 20-Fold Price Increase (Case Study Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
AMRN-B							
30395_31445	**COFFEEN**	**PANA**	**AMRN-B**	**AMRN-B**	**345**	**kV**	**Line**
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

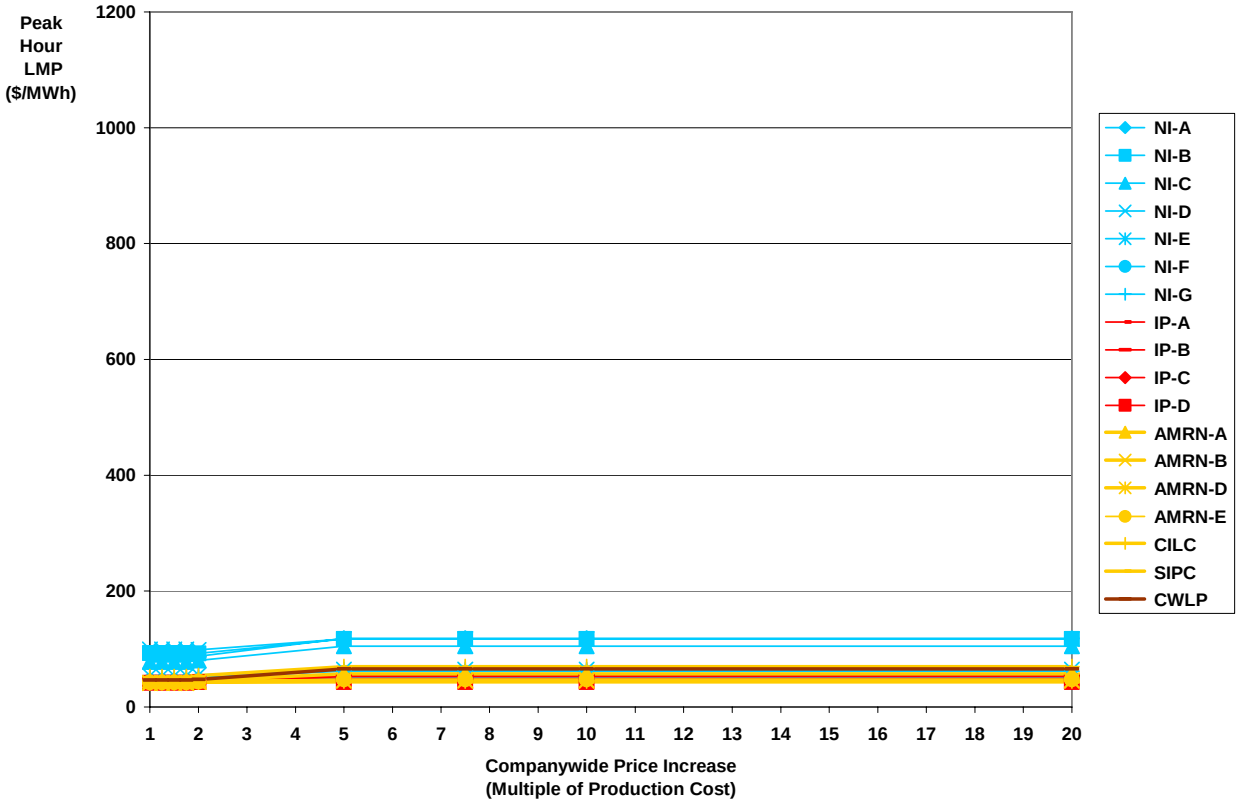

Figure 4.3.2-28 Dominion Energy Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

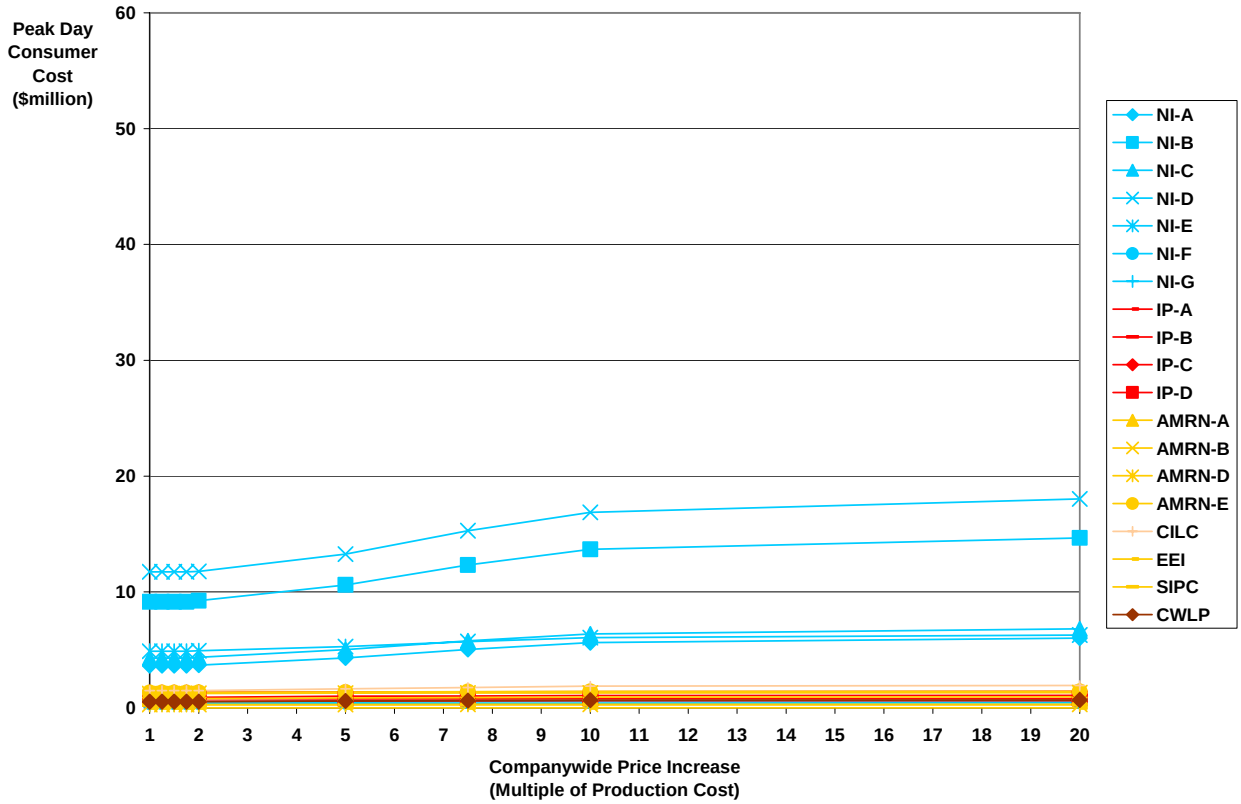

Figure 4.3.2-29 Dominion Energy Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-30 shows the generation and operating profit under Conservative Assumptions. The result was essentially the same as for Case Study Assumptions. Table 4.3.2-10 shows the transmission components at capacity limits. As before, company profitability did improve as a result of the changes in congestion.

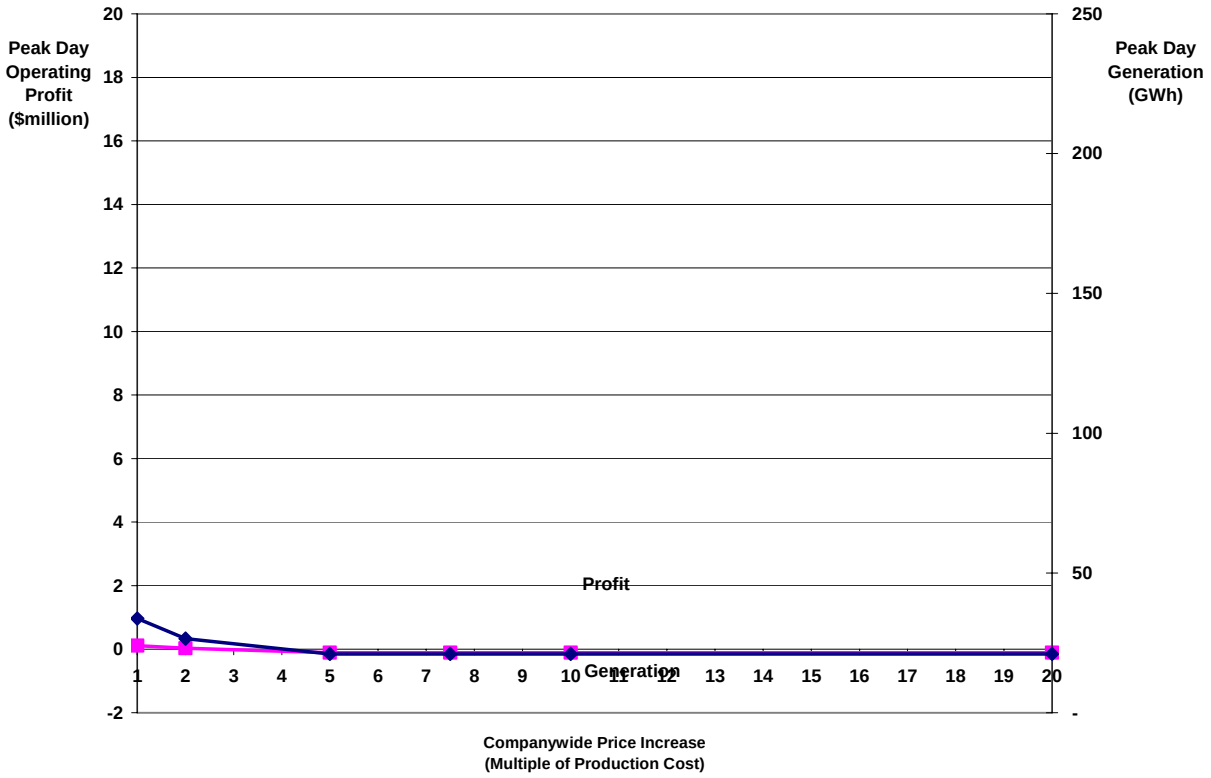

Figure 4.3.2-30 Dominion Energy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-10 Transmission Components at Capacity Limits under Dominion Energy 20-Fold Price Increase (Conservative Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36867_37387	**JEFFE; R**	**KINGS; R**	**NI-D**	**NI-D**			
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
AMRN-B							
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer
30395_31445	**COFFEEN**	**PANA**	**AMRN-B**	**AMRN-B**	**345**	**kV**	**Line**
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line
AMRN-D							
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
EEI							
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Company Comparison

Case Study Assumptions

The previous sections have focused on the effects of economic withholding from the perspective of individual companies. To compare the results across companies requires an adjustment in the measurement scales used to display results. Previously, the multiplier that each company applied to the production cost of its units was used as the metric. However, each company has a different portfolio of units, each with a different production cost. The unit production costs range from very low for nuclear and large coal units, to very high for gas turbine peaking units. Applying companywide multipliers to bid prices amplified the wide range of production costs. Figure 4.3.2-31 shows the range of unit production costs for each company along with a capacity-weighted average. It is evident that, for example, a doubling of prices by one company can create a very different set of market bids than a doubling of prices by another company. For the cross-company comparisons, the capacity-weighted average price was used as the metric in place of the companywide price multiplier.

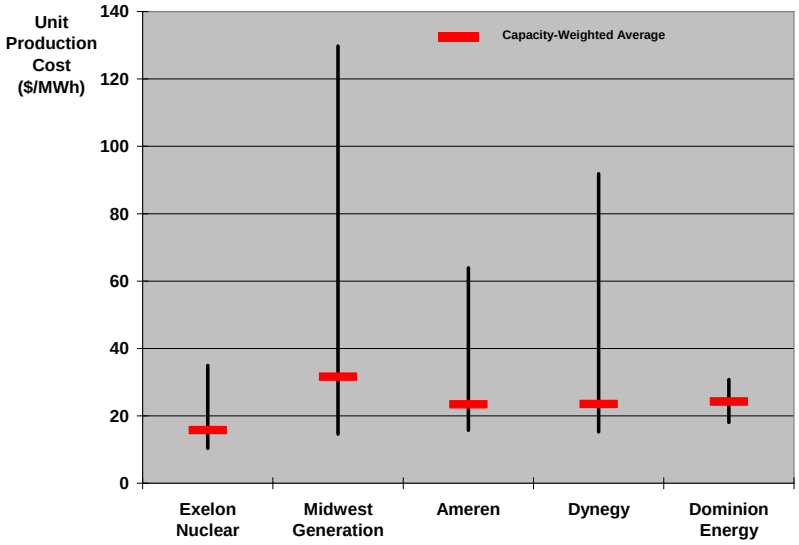

Figure 4.3.2-31 Range of Unit Production Costs and Capacity-Weighted Average

Figure 4.3.2-32 shows the effect that price increases, to the same capacity-weighted average for each company, had on consumer prices in each zone. All companies, with the exception of Dynegy, had the ability to impact consumer costs in the northeastern part of the State (i.e., the NI zones). A price increase to a companywide average of 300 $/MWh caused consumer costs to rise between 50% and 250%, depending on which company was implementing the increase. Some of the companies operating in one part of the State had the ability to create consumer price increases in other parts of the State, as shown on the figure. Some parts of the State (i.e., the IP and AMRN zones) were relatively insensitive to the price increases from any company. Consumers in these areas did not experience any significant cost increases even at the high price levels. All these results reflect the transmission limits discussed earlier.

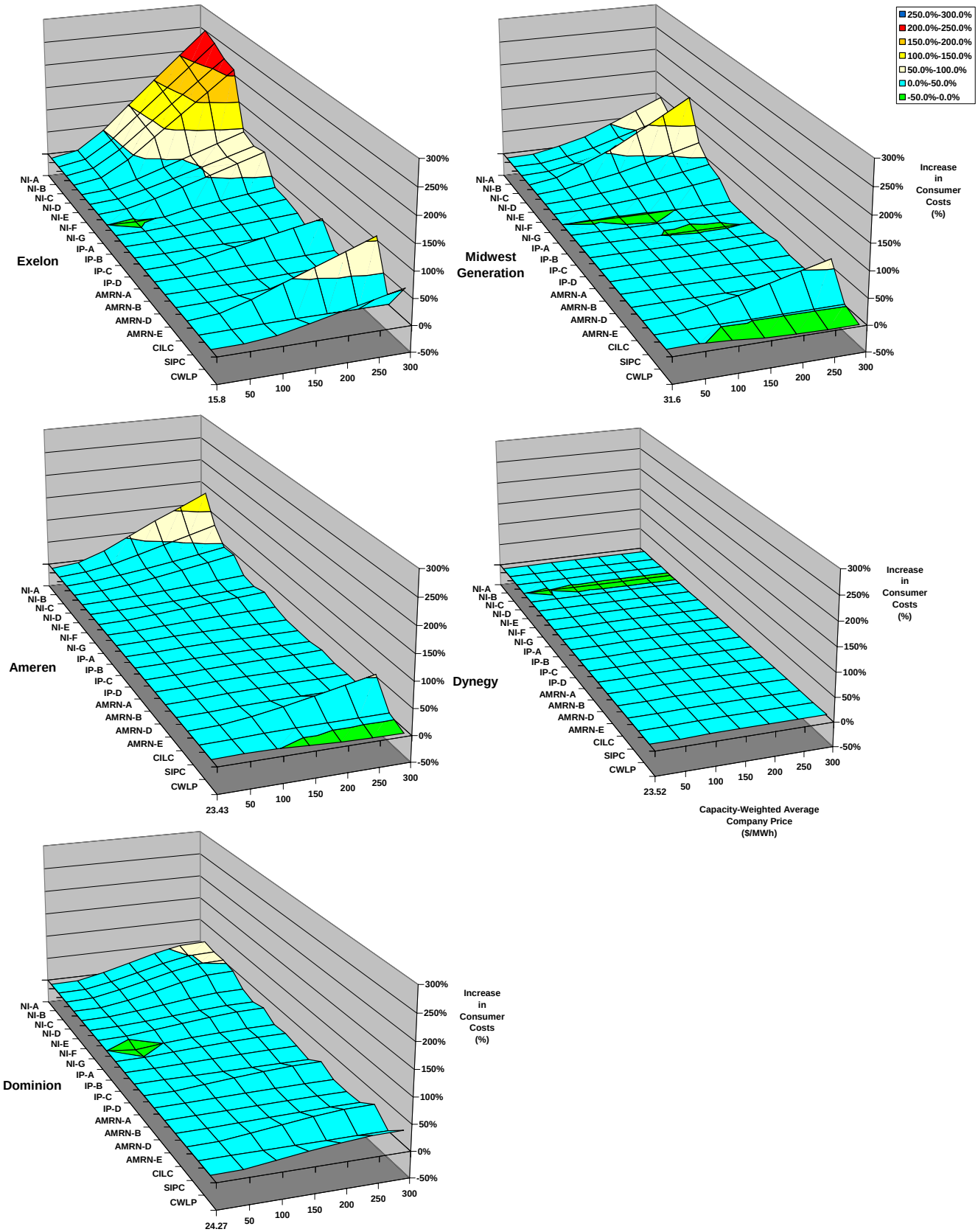

Figure 4.3.2-32 Effect of Companywide Price Increases during Peak Hours on Consumer Costs (Case Study Assumptions)

These results stem from the integrated operation of the electricity market as assumed in the simulation. Because the market was operated by a single ISO rather than by individual companies, any generator in any part of the State could be used to meet load in any other part of the State, subject to the limits of the transmission system. Thus, price increases by any one company had the potential to ripple across the State and affect the entire market. This was especially true for the companies that had large units located at critical points in the transmission network such as Exelon Nuclear, Midwest Generation, and Ameren. By raising their prices, they affected most of the market.

The parts of the State that are not significantly affected by these price increases had adequate lower-cost generation combined with transmission capacity to bring the cheaper power into the area. These areas were effectively insulated from price increases by the large GenCos. In an analogous fashion, the fact that price increases by Dynegy did not have the ability to affect much of the market indicates that their units are not as strategically located as those of other companies. At higher prices, their units were readily displaced by others.

Conservative Assumptions

Figure 4.3.2-33 shows the range of production costs and capacity-weighted average under the Conservative Assumptions. The difference from the previous figure is that fixed operating and maintenance costs have been excluded. The company comparison was repeated using these values of production cost. Figure 4.3.2-34 shows the effect of company price increases on consumer costs.

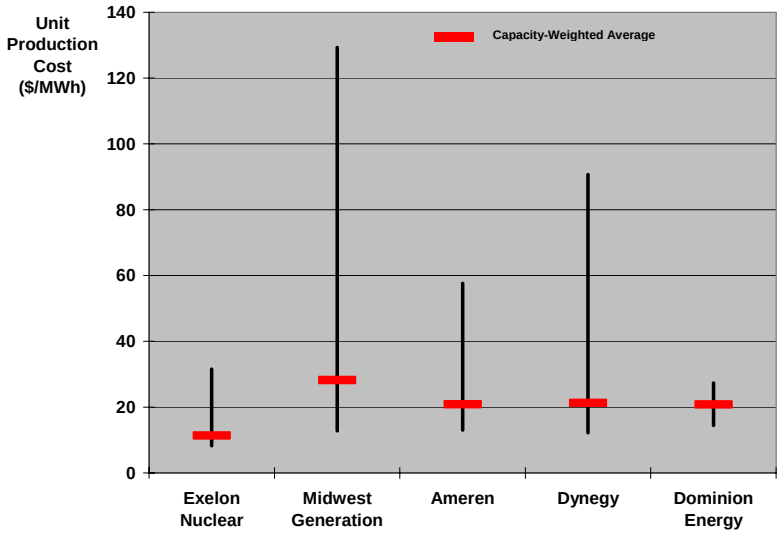

Figure 4.3.2-33 Range of Unit Production Costs and Capacity-Weighted Average (Conservative Assumptions)

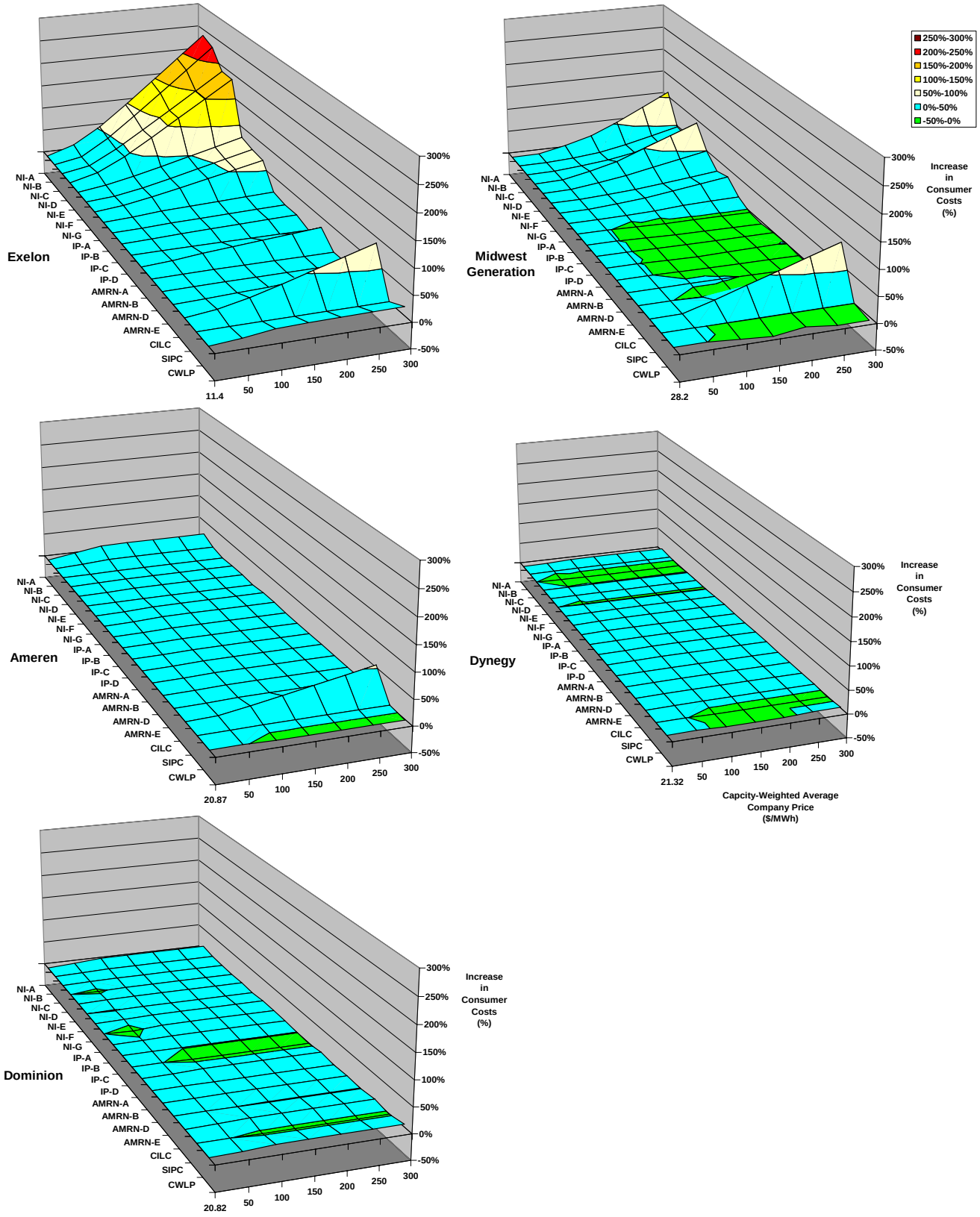

Figure 4.3.2-34 Effect of Companywide Price Increases during Peak Hours on Consumer Costs (Conservative Assumptions)

For Exelon Nuclear, Midwest Generation, and Dynegy, the pattern was very similar, in terms of percentage increase, to the Case Study Assumptions; however, the absolute level of increase was lower under these conditions. This was due to the availability of more generation, since forced outages and company-level unit commitment were not considered here. For Ameren and Dominion, the impact of their price increases on consumer costs in the northern parts of the State was reduced considerably as a result of the availabilty of this extra generation capacity statewide under the Conservative Assumptions.

4.3.3 Economic Withholding Summary

The following summary observations can be made with respect to the economic withholding strategy:

- Economic withholding of single units (i.e., raising prices above production costs for one unit in a company's portfolio) did not generate significant increases in operating profitability. In most cases, it created a loss as the unit's dispatch schedule was reduced. There was adequate generation and transmission capacity to bring cheaper units on-line.

- For a few units that were critical during peak hours, single unit economic withholding provided an increase in operating profit.

- Companywide economic withholding during all hours of a peak-load day was not an attractive strategy for all companies. The higher-priced units were not scheduled for dispatch during low-load periods. The price increases did not compensate for the loss of scheduled generation. In some cases (e.g., large nuclear or coal-fired units), the reduced dispatch schedule was not technically feasible.

- Companywide economic withholding only during peak hours did increase company operating profit significantly on peak days for Exelon Nuclear and Midwest Generation. For Ameren, Dynegy, and Dominion Energy, profitability decreased.

- All companies, with the exception of Dynegy, had the ability to increase market prices by companywide economic withholding on peak days. However, only Exelon Nuclear and Midwest Generation gained significant increases in operating profitability by applying this strategy. Ameren, Dynegy, and Dominion Energy did not have market power by this criterion. Under the Conservative Assumptions, Midwest Generation still displayed the ability to exercise market power. For Exelon Nuclear, under Conservative Assumptions, its prices had to be raised beyond the 20-fold level used here in order for its profits to increase measurably.

- All companies, except Dynegy, caused peak-day consumer costs to rise by the application of a companywide economic withholding strategy. The northeastern part of the State experienced peak-day consumer cost increases of 2½ times. Under Conservative Assumptions, the same was true except that the level of consumer price

increases was smaller. Also, Ameren and Dominion had significantly smaller impacts on consumer prices from their increases.

- As a result of transmission limits, the NI and CILC zones were the most susceptible to the exercise of market power using economic withholding. The IP and AMRN zones were affected to a much smaller degree due to less transmission congestion. This was true under both Case Study and Conservative Assumptions.

5 SUMMARY

5.1 OBSERVATIONS AND CONCLUSIONS

As was stated in the opening section of this report, the purpose of this study was to make an initial determination of whether or not 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 as the State moves toward full restructuring of the electricity market in 2007. The study was designed to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power (defined here as the ability to unilaterally raise prices and increase company profitability) 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. The results indicate that the answers to these questions are not simple. Rather, they depend on a number of factors. The following observations can be made from what has been studied thus far under the assumptions applied:

Basic System Status

(a) The State has an adequate supply of generation capability to meet its needs and to export power to surrounding areas. It might even be argued that there is an excess of capacity, given that the projected statewide generation reserve margin (in excess of 40%) is higher than what is generally used for system reliability planning. Further, some generators would not be dispatched at all under the conditions laid out in the PC case.

(b) The ownership of the generation capacity is concentrated in five companies: Exelon Nuclear, Midwest Generation, Ameren, Dynegy, and Dominion Energy. Together, they account for more than 77% of the generation capacity in the State. If they were to be dispatched under PC case market conditions, they would account for about 98% of the electricity generated in the State. Using any one of a number of measures of market competition, the State's generation capacity can be considered to be concentrated. With this degree of concentration and with much of this capacity in the form of low-cost nuclear and coal units, it would be difficult for new generation companies to enter the deregulated market. In fact, many of the existing natural gas units, some of which are only a few years old, would have difficulty competing in this market.

(c) During the high-load periods, which occurred about 5% of the time, electricity prices rose, since higher-cost generators had to be brought on-line to meet loads while maintaining the integrity and stability of the power grid. Even without any attempt to manipulate prices on the part of generation companies, prices were as much as 30% higher in high-load periods.

(d) The transmission system in the State has areas that show evidence of congestion. Some transmission equipment was operated at its capacity limits for a significant number of hours in a year. The congested regions include the City of Chicago, the area north and west of Chicago out to the Iowa border, a broad area stretching southwest of Chicago to Peoria and Springfield, and several smaller isolated areas in the southern part of the State. The effects of the transmission congestion on locational marginal prices were most prevalent during peak-load periods during which there was a pronounced price spread across the State. Price variations across the State due to transmission congestion were as much as 24% during these peak-load periods.

(e) Using Conservative Assumptions, in which more generation capacity was assumed to be made available by the elimination of forced outages and company-level unit commitment decisions, the results did not materially change. The generation market was still concentrated and transmission congestion was still evident. Price variations, though smaller in absolute magnitude, were equivalent in relative terms.

(f) Under a fully competitive market in the State using the market rules assumed here, some generation companies were pressed to maintain operating profitability. Only 6 out of 24 generation companies in the State were able to operate profitably. The dominance of the low-cost nuclear and coal units made it difficult for others to compete. Under Conservative Assumptions, none of the generation companies, except Exelon Nuclear, was profitable. Exelon's operating profit was very small.

Market Power Potential

(g) If generation companies seek to raise market prices by physically withholding single units from service, the results here show that, for the most part, they would not likely benefit. Because of the abundance of generation in the State, there was almost always another unit that could be brought into service to replace one that was withheld. This is true even in light of the transmission limitations.

(h) In contrast, physically withholding multiple units that are strategically located in the transmission network, particularly during peak-load conditions, can increase profitability. A single company using a strategy based on indicators of system reserve margin to identify times to withhold capacity and indicators of locational prices to identify which capacity to withhold could significantly increase its profitability. This type of strategic physical withholding could even create conditions where some load cannot be met and could result in very steep price increases. Exelon Nuclear, Midwest Generation, and Ameren all had market power (as defined here) when using this strategy. Dynegy and Dominion Energy did not.

(i) If the major generation companies sought to raise market prices by unilaterally increasing the price of their units (i.e., by economic withholding) the results would be mixed. Applying a price increase to all units for all hours increased profits for Exelon Nuclear and Midwest Generation, but at the expense of significant loss in generator

dispatch, since some of the higher cost units would be selected only sporadically by the market. The resulting dispatch schedule may not be technically practical for the companies' larger units. For Ameren, Dynegy, and Dominion Energy, the higher priced units would not be selected in the market and the price increase gained by other units would not be sufficient to recover the lost revenue. Profitability decreased.

(j) Alternatively, a more limited application of price increases that was restricted to peak hours only allowed Exelon Nuclear and Midwest Generation to significantly increase profits with only a small decrease in generator dispatch. Ameren, Dynegy, and Dominion did not see any profit increase by applying this strategy. The same was true under Conservative Assumptions except that Exelon would need very large price increases to increase its profitability. When using this strategy, Exelon Nuclear and Midwest Generation had market power, according to the definition used here.

(k) By raising their prices, all generation companies could cause consumer costs to rise, some by as much as 250% in some parts of the State on a peak day. However, only Exelon Nuclear and Midwest Generation saw a significant increase in their operating profits by applying this strategy.

Overall, the answer to the basic question of the study, *"Can a company, acting on its own, raise electricity prices and increase its profits?"* is affirmative. There is a concentration in the generation market and evidence of transmission congestion, at least during high-load periods. This will give rise to the ability of some companies to unilaterally raise prices and increase their profits. Consumer costs will increase, in some cases substantially. However, the situations under which this can be done are limited to a number of conditions, especially high-load periods.

5.2 RECOMMENDED ADDITIONAL ANALYSIS

All of the results presented here must be viewed in the light of the limitations of the models, data, and assumptions used. Further, the results presented here provide only an initial indication of how the Illinois electricity market might function. There are many more issues and conditions that need to be investigated to provide a more comprehensive picture of the situation.

A number of additional analyses can be identified to increase the understanding of possible developments in the Illinois market. Included are the following:

- *An expansion of the level of detail in the representation of the out-of-state grid.* The results of both the PowerWorld and EMCAS models showed that out-of-state suppliers and out-of-state loads can have a significant impact on the Illinois market. A more detailed representation of these factors would improve the understanding of these effects.

- *Sensitivity analyses that vary some of the key parameters over a range of possibilities.* Included are:

- Fuel price forecasts
- Forced outage scenarios
- Transmission system configuration
- Decision parameters used in the strategies

- *Evaluation of additional company business strategies.* Only a few business strategies were studied here. There are many more that could be evaluated for their impact on the market.

- *Evaluation of the effect of bilateral contracts.* In this study, it was assumed that there would be no bilateral contracts between GenCos and DemCos. All power would be traded in a pool market. The effect of bilateral contracts, which could mitigate some of the price swings, should be investigated.

- *Effect of consumer price response.* In this study, it was assumed that there is no consumer response to prices and electricity demand is inelastic. An evaluation of how consumers might respond (e.g., by reducing load, by switching electricity suppliers) should be studied.

- *Effect of adding generation and/or transmission resources.* In this study no new transmission resources were added to the system. Modified locations for generation resources (e.g., distributed generation designed to reduce transmission congestion) were also not included here. Both of these warrant further evaluation.

- *Changes in market rules.* This study considered only a single market configuration and a single set of market rules. The effects of changes in the market structure, market rules, and regulatory measures to mitigate against steep price increases need to be studied.

The value of this study and any subsequent studies is not in producing a single projection of how the Illinois electricity market will develop, nor to consider a set of possible scenarios for its development. Rather, the benefit is gained by identifying the configurations to which the market may gravitate. In the terminology of the computer modeling and simulation that was used here, this would "map the solution space." This approach will provide a better understanding of the fundamental forces at work that will shape the evolution of the Illinois electricity market.