APPENDIX
TO
REPORT REGARDING THE EXPECTED COMPETITIVENESS OF MARKETS IN THE NORTHERN ILLINOIS CONTROL AREA AFTER INTEGRATION INTO PJM

PJM MARKET MONITORING UNIT

SEPTEMBER 24, 2003

1. Introduction

The PJM Market Monitoring Unit (MMU) performed an analysis of expected market conditions in the Northern Illinois Control Area (NICA)[1] after integration into PJM, including the expected role of competition from the surrounding control areas. Based on that analysis, the MMU has reached conclusions regarding the expected competitiveness of the markets in the NICA following its integration into PJM. The relevant markets in the NICA include the energy markets, the capacity market, the ancillary services markets including regulation and spinning reserves, and the "markets" for blackstart and reactive services. Blackstart services and reactive services will be provided per tariff rates rather than via a clearing market. The MMU analysis included an examination of the structure of supply and demand within the NICA for the relevant markets and a series of simulations of the entire Eastern Interconnection focusing on the NICA energy market and the interaction between the NICA energy market and the PJM energy market, using the GE MAPS model.

This Appendix provides additional information regarding the methods used, the assumptions and the results of the MMU analysis.

2. NICA Analysis

The analysis of the NICA market was based on unit by unit generation information, hourly loads, generation ownership and bilateral contracts. Table 1 is a list of the generating units included in the NICA market analysis. Figure 1 is the load duration curve for the NICA. Generator data, including cost data, was drawn from public data sources and hourly load was provided by Commonwealth Edison.

3. Eastern Interconnection Analysis

a. Model

The Eastern Interconnection analysis was based on the General Electric Multi-Area Production Simulation Model (GE MAPS or MAPS). MAPS is a production simulation model including, in this case, a full model of the entire Eastern Interconnection including all generating units and a fully detailed transmission model. The MAPS model represents an optimal, security constrained dispatch based on the marginal costs of generating units, transmission system capabilities and bus-level loads that operates on an hourly basis. The MAPS model is consistent with the operation of the PJM system that produces bus-specific LMP based on a security constrained dispatch.

b. Hurdle Rates

The basic GE MAPS approach, as outlined above, would result in an optimal, security constrained, economic dispatch of the entire Eastern Interconnection if operated without any institutional or economic limitations. The intent of the MMU modeling was to include the impacts of the existing limitations to such a dispatch. These limitations affect the level of economic transactions between areas and fall into the general categories of transmission rates and economically inefficient dispatch. Existing control areas and transmission owners have transmission rates that must be

[1] This area has been referred to, at times, as the Commonwealth Edison (ComEd) region.

paid in order for transactions between control areas to take place. In addition, in the absence of a central economic dispatch there are other constraints on the dispatch of generation across areas that results in less than efficient dispatch, when evaluated over the entire, broader area.

So called "hurdle rates" are used in production simulation models to represent transmission rates and the existing limitations on economic dispatch so that the simulation results accurately reflect these limitations as well as the removal of certain limitations that will result from the integration of NICA and PJM. The essential point about hurdle rates is that they represent the test or hurdle that must be passed or exceeded before economic transactions between areas will take place in the model. The MMU analysis included two basic approaches to hurdle rates. The analysis used, as one sensitivity case, the approach used by PJM in its cost-benefit analysis. This sensitivity case was termed the 15/9 case, based on the hurdle rates used. The MMU analysis used, as a second sensitivity case, an approach that modeled hurdle rates based on historical interregional market price differentials. The second sensitivity case was termed the Variable Hurdle Rate case. A variant of the Variable Hurdle Rate case was run which modeled the explicit removal of all PJM/MISO through and out rates, consistent with the FERC Order in Docket EL02-111 issued July 23, 2003. This case was termed the Variable Hurdle Rate – RTOR case. In all hurdle rate sensitivity cases, the hurdle rate for PJM-NICA transactions along the pathway was set to zero to reflect the fact that no transmission rates apply to pathway transactions and that units within the broader PJM-NICA market will be dispatched based on economics so that the most efficient dispatch will occur without artificial barriers.

The 15/9 hurdle rate case used a hurdle rate of $15 per MWh when a unit had to be started in order to provide energy and a hurdle rate of $9 per MWh when a unit was already operating. The higher hurdle rate ($15/MWh) is applied in order to reflect the costs associated with starting a unit, spread over the expected hours of operation. In the 15/9 hurdle rate case, the hurdle rates were applied whenever energy moved from one control area to another. The hurdle rates are additive so that, in order for energy to move from control area one, through control area two to control area three, the hurdle rate would be applied once for moving from control area one to control area two and again for moving from control area two to control area three. In addition, hurdle rates in this sensitivity case were applied along the electrical path of the energy. Thus, for example, if energy flows from control area one to control area three, the actual control areas that the energy flows through are based on the underlying impedances of the transmission system. The number of hurdle rates paid are a function of how many control areas the energy flowed through. It is possible that energy actually flowed through two intermediate control areas to reach control area three and the hurdle rates applied would reflect those facts.

The variable hurdle rate cases were based on an analysis of actual historical differentials in observed prices between representative trading hubs. In addition, the variable hurdle rate sensitivity cases modeled transactions on a transmission pathway basis rather than on an electrical flow basis. Thus, in order for energy to flow from control area one to control area three by going through control area two, only the hurdle rates associated with the contract path would be included. This reflects the reality of how transmission rates are actually applied and of how energy contracts are structured, outside of LMP-based markets. In addition, the Variable Hurdle Rate - RTOR sensitivity case reflects the removal of through and out rates by FERC for any MISO- PJM transactions. The hurdle rates used in the variable hurdle rate sensitivity cases are shown in Tables 2 and 3.

4. Results

a. Pathway Conditions

The attached Figures show the number of hours and the proportion of hours during which the pathway is unconstrained, constrained from PJM to NICA and constrained from NICA to PJM. Results are shown for both the hurdle rate cases.

i. Unconstrained Pathway Scenario

When the pathway is not constrained and, as a result, when the NICA and the PJM region are jointly dispatched, the combined energy market is expected to be competitive and therefore the energy market in the NICA is expected to be competitive. The results of the MMU analysis indicate that the pathway is expected to be unconstrained from about 30 percent of the hours annually under the 15/9 hurdle rate scenario to about 15 percent of the hours annually under both the variable hurdle rate and variable hurdle rate - RTOR scenarios. (See Figure 2.)

ii. NICA to PJM Constrained Pathway Scenario

When the pathway is constrained from the NICA to the PJM region, the energy market in the NICA is expected to be competitive under normal market conditions. The results of the MMU analysis indicate that the pathway is expected to be constrained from the NICA to the PJM region from about 60 percent of the hours annually under the 15/9 hurdle rate scenario to about 80 percent of the hours annually under the variable hurdle rate and variable hurdle rate - RTOR scenarios. (See Figure 3.)

However, there are market power concerns regarding the NICA market when the pathway is constrained from the NICA to the PJM region, when there are extreme market conditions in the PJM region but not in the NICA and when NICA generation cannot substitute for PJM generation regardless of path.

Based on the experience in PJM, there are expected to be only a small number of hours when the pathway is constrained from NICA to PJM, when PJM faces high demand conditions while NICA does not and when NICA generation cannot substitute for PJM generation, regardless of path. PJM average system prices have exceeded $500 per MWh for only about 0.19 percent of the hours since April 1, 1999. (See Figure 4.)

iii. PJM to NICA Constrained Pathway Scenario

When the pathway is constrained from the PJM region to the NICA, there are market power issues regarding the energy market in the NICA. The results of the MMU analysis indicate that the pathway is expected to be constrained from the PJM region to the NICA from about 10 percent of the hours annually under the 15/9 hurdle rate scenario to about 5 percent of the hours annually under the variable hurdle rate and variable hurdle rate - RTOR scenarios. (See Figure 5.)

b. Imports and Exports

Regardless of pathway conditions, the energy market in the NICA will experience competition from external sources. NICA resources may export to external areas and external resources may import into NICA. The GE MAPS simulations result in calculations of the level of economic exports from and imports to NICA. Table 4 shows the directly interconnected control areas. NICA import and export results are shown in Figures 6 through 11 for all hurdle rate scenarios by on peak and off peak periods. In the variable hurdle rate - RTOR case, exports from NICA to MAIN increased, when compared to the other two scenarios. It appears that this increase in exports resulted from the removal of through and out rates between PJM and MISO mandated by FERC Order EL02-111. NICA generation displaced more expensive generating units in surrounding control areas, particularly during off-peak periods when through and out rates were removed.

c. Local Market Power

Regardless of pathway conditions, the energy market in the NICA may face local market power issues when units are required to run for local constraints to maintain reliability, exactly as is the case in the PJM region. Tables 5 through 7 show the constrained NICA facilities and the proportion of hours during which they were constrained in each scenario. The west to east 345 kV transmission lines were the most constrained. The most limited line was between Cherry Valley and Silver Lake, closely followed by the Nelson to Electric Junction line. The 345 lines from Quad Cities to Cordova and from Quad Cities to Electric Service Station H 471 were also constrained a significant proportion of hours. The simulation scenarios resulted in congestion simultaneously on one or more facilities during more than 50 percent of all hours. Figure 12 is a partial map of the outer transmission system of ComEd showing these facilities. The outer transmission facilities are those which lie beyond the immediate vicinity of the City of Chicago.

d. Market power mitigation

i. Unconstrained Pathway Scenario

Based on the analysis of competitive conditions, market power mitigation measures for aggregate market conditions are not expected to be required when the NICA and the PJM region are jointly dispatched and the pathway is not constrained. There are no automatic aggregate market power mitigation mechanisms in place in PJM because the aggregate energy market results are competitive. When the NICA is added to the PJM market, the entire market is larger and more diverse and the expectation is that aggregate market results will continue to be competitive.

ii. *NICA to PJM Constrained Pathway Scenario*

Based on the analysis of competitive conditions, market power mitigation measures for aggregate market conditions are not expected to be required under normal market conditions when the pathway is constrained from the NICA to the PJM region. Again, the combined PJM and NICA markets are expected to produce competitive results when PJM loads are in the relatively flat portion of its aggregate supply curve.

Based on the analysis of competitive conditions, market power mitigation measures for aggregate market conditions will be required when the pathway is constrained from the NICA to PJM, when there are extreme market conditions in the PJM region but not in the NICA and when NICA generation cannot substitute for PJM generation regardless of path. While the ideal situation would be that competition from areas outside the NICA would provide adequate competitive pressures in the NICA market, there is not adequate certainty that this will be the case. As a result, aggregate market power mitigation mechanisms must be in place in NICA to address this issue. These aggregate market power mitigation measures in NICA must strike a balance between preventing any exercise of market power and ensuring that a competitive market price signal is permitted to emerge from the markets. In addition, the aggregate market power mitigation mechanism must be designed so as not to limit prices in the NICA market if generation in that market has the ability to deliver power to higher price markets and thus faces the associated higher, external opportunity cost. The PJM MMU proposes to limit bids to marginal cost plus ten percent in the NICA region for units at the margin during the identified conditions. Marginal cost is defined to include opportunity cost and risk components. The MMU will also continue to engage in discussions with generation owners in NICA to determine if alternate methods of market power mitigation are feasible.

At present, PJM does not have an aggregate market power mitigation mechanism in place for PJM because the results of the PJM energy market as a whole are generally competitive on a standalone basis. No aggregate market power mitigation measures are proposed for PJM as a result.

iii. *PJM to NICA Constrained Pathway Scenario*

Based on the analysis of competitive conditions, market power mitigation measures for aggregate market conditions will be required when the pathway is constrained from the PJM region to the NICA. When the pathway is constrained from PJM to the NICA, there is no competitive pressure from PJM units. The competitive pressure on the NICA market that may result from other generation is uncertain. As a result, generators in the NICA may be able to exercise market power under these conditions. Again, while the ideal situation would be that competition from areas outside the NICA would provide adequate competitive pressures, there is not adequate certainty that this will be the case. Thus, aggregate market power mitigation mechanisms must be in place to address this issue. These mitigation measures must strike a balance between preventing the exercise of market power and ensuring that a competitive market price signal is permitted to emerge from the markets. The PJM MMU proposes to limit bids to marginal cost plus ten percent in the NICA region for units at the margin during the identified conditions. Marginal cost is defined to include opportunity cost. The MMU will also continue to engage in discussions with generation owners in NICA to determine if alternate methods of market power mitigation are feasible. The MMU will also monitor competitive pressures from areas outside NICA to determine if they will permit the modification of the proposed market power mitigation methods.

iv. Monopsony

No explicit monopsony-based market power mitigation rules will be proposed at the outset of this market. The fact that the markets will be based on a centrally operated, least cost, security constrained dispatch should address these concerns, together with the ability of all parties to take purely financial positions in the day-ahead market. Nonetheless, the potential exercise of monopsony power in the energy market will be carefully monitored by the MMU as the market develops.

v. Local Market Power

Regardless of aggregate market conditions, local market power mitigation measures will be required when units are required to run for local constraints to maintain reliability. This is the same situation that currently exists in PJM where units are subject to local market power mitigation rules when units are required to run for local constraints. The PJM local market power mitigation rules should apply to all units in the NICA, regardless of the date of construction. There is nothing about the date of construction that reduces the need to prevent the exercise of local market power.

5. The Capacity Market

a. Market Conditions

There is currently no formal capacity market in the NICA. It is expected that, when the capacity market begins, as the result of the structural conditions in the NICA market that the capacity market in the NICA will face market power issues. As in the PJM capacity market, it is expected that the structure of capacity ownership and the nature of the capacity markets will result in the ability of some generators to exercise market power in the NICA capacity market. The monopsony market power issue identified in the energy market also exists in the capacity market.

The calculated HHI for the capacity market is 2150. In addition, the MMU analysis indicates that at least two generation owners will be pivotal in the capacity market. In other words, the capacity of these owners will be required in order to meet total load obligations to purchase capacity.

b. Market power mitigation

Based on the analysis of competitive conditions, market power mitigation measures will be required for the NICA capacity market. While the exact details will be developed in the coming period prior to the opening of the capacity markets on June 1, 2004, these mitigation measures will be designed to limit offers in the capacity market to the marginal cost of capacity where marginal cost is defined to include all aspects of marginal costs including, where relevant, going forward costs, opportunity costs and risk. In addition, these mitigation measures will address market pricing during periods of shortage or scarcity by permitting the price of capacity to increase during such periods. Again, the market power mitigation measures must strike the balance between preventing the exercise of market power and ensuring that a competitive market price signal is permitted to emerge from the markets. No explicit monopsony-based market power mitigation rules will be proposed at the outset of this market. The fact that the markets will be based on a centrally operated auction and that LSEs must purchase an externally defined quantity of capacity resources should limit this potential. Nonetheless, the potential exercise of monopsony power in the capacity market will be carefully monitored by the MMU as the market develops.

6. Regulation Market

a. Market conditions

The regulation market in the NICA appears to be highly concentrated. Ownership of regulation capability appears to be concentrated in the hands of a very small number of generation owners. Regulation must be obtained either from resources within the NICA or resources dynamically scheduled into the NICA, so potential competition from external resources will not be a significant constraint in the regulation market.

b. Market power mitigation

Based on the structural analysis of the regulation market in the NICA, market power mitigation measures will be required for the regulation market. This is in contrast to the PJM Eastern Region where there is a competitive regulation market with an offer cap of $100. However, in the PJM Western Region there is not a competitive market in regulation and regulation is provided at cost.

The MMU proposes that the regulation market be a cost-based market in the NICA until adequate competition develops to permit a market design like that in the PJM Eastern Region. Costs would include the incremental costs of providing regulation plus opportunity costs.

7. Spinning Reserves Market

a. Market conditions

The spinning reserve market in the NICA appears to be highly concentrated. Ownership of generation with spinning reserve capability appears to be concentrated in the hands of a very small number of generation owners. Spinning reserves must be obtained either from resources within the NICA or dynamically scheduled into the NICA, so potential competition from external resources will not be a significant constraint in the spinning reserve market.

b. Market power mitigation

Based on the structural analysis of the spinning reserve market in the NICA, market power mitigation measures will be required for the spinning reserve market.

The MMU proposes that the spinning market in the NICA be structured as it is in the PJM Eastern Region. For Tier 1 spinning reserves, payments for spinning reserves are made only when actual spinning reserves are provided and the prices paid for those reserves are based on five-minute LMPs plus a fixed adder. For Tier 2 spinning reserves, availability payments are made based on costs plus a $7.50 margin and all resources receive the market clearing price. Opportunity costs are included in payments to spinning reserves resources.

8. Blackstart

a. Market conditions

As in PJM, blackstart services in the NICA do not lend themselves to being organized as a competitive market as the structural conditions for a competitive market do not exist. Blackstart services must be provided from resources within the NICA, so potential competition from external resources will not be a constraint on blackstart pricing.

b. Market power mitigation

In the NICA, as in the PJM region, the MMU proposes that blackstart services should be provided at cost pursuant to the PJM Tariff.

9. Reactive

a. Market conditions

As in PJM, reactive services in the NICA do not lend themselves to being organized as a competitive market as the structural conditions for a competitive market do not exist. Reactive services must be provided from resources within the NICA, so potential competition from external resources will not be a constraint on reactive pricing.

b. Market power mitigation

In the NICA, as in the PJM region, reactive services should be provided at cost pursuant to the FERC-approved rates, subject to PJM's determination that the purchased quantity of reactive services is needed.

10. Summary

The PJM MMU expects, based on our analysis, that the NICA energy market will be competitive under most market conditions. Based on the simulations, the MMU expects that the energy market will be competitive from 90 to 95 percent of annual hours. For the remaining hours, the MMU proposes market power mitigation mechanisms that must be in place to ensure that market power is not exercised in the aggregate NICA energy market. The MMU will continue to engage in discussions with market stakeholders to determine if these measures can be improved.

The PJM MMU expects that there will be market power issues in the capacity market when it is implemented on June 1, 2004. The PJM MMU proposes market power mitigation mechanisms that must be in place to ensure that market power is not exercised.

The PJM MMU expects that there will be market power issues in the regulation market. As a result, the PJM MMU proposes that the regulation market be a cost-based market in NICA until adequate competition develops to permit a market design like that in the PJM Eastern Region.

The PJM MMU expects that there will be market power in the spinning reserves market. As a result, the PJM MMU proposes that the spinning market in NICA be structured as it is in the PJM Eastern Region.

The PJM MMU's view is that blackstart services and reactive services do not lend themselves to being organized as competitive markets. As a result, the PJM MMU proposes that both blackstart services and reactive services be provided at cost pursuant to the PJM Tariff and FERC-approved rates.

Figure 1.

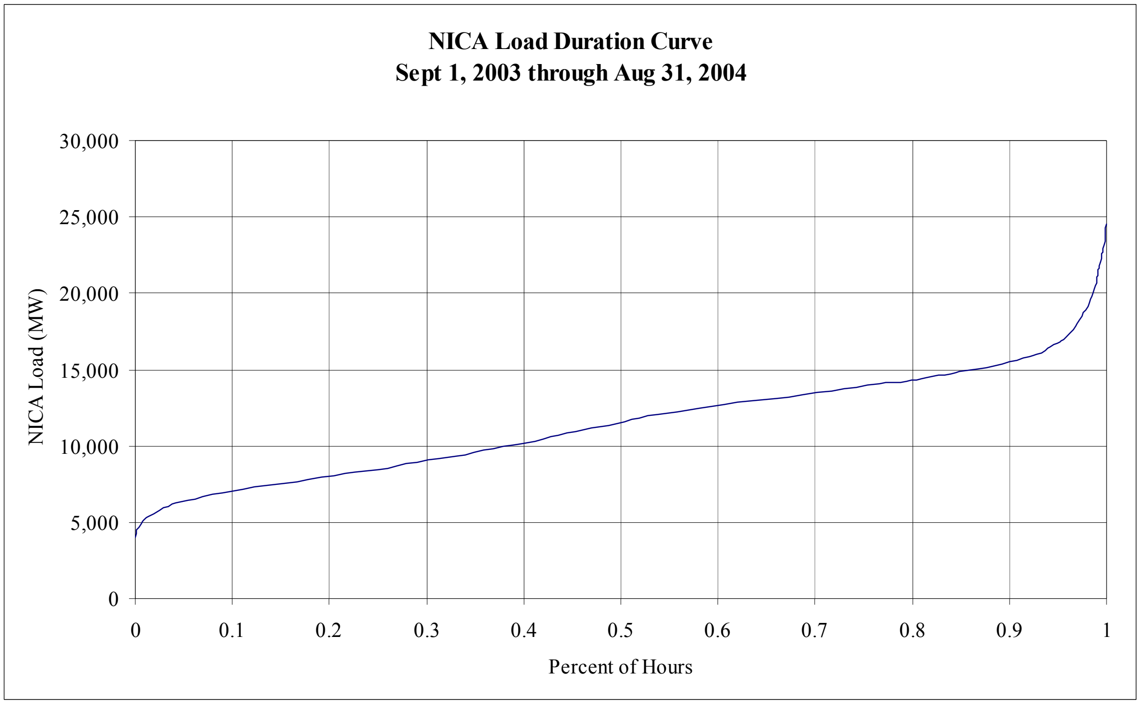


Figure 2.

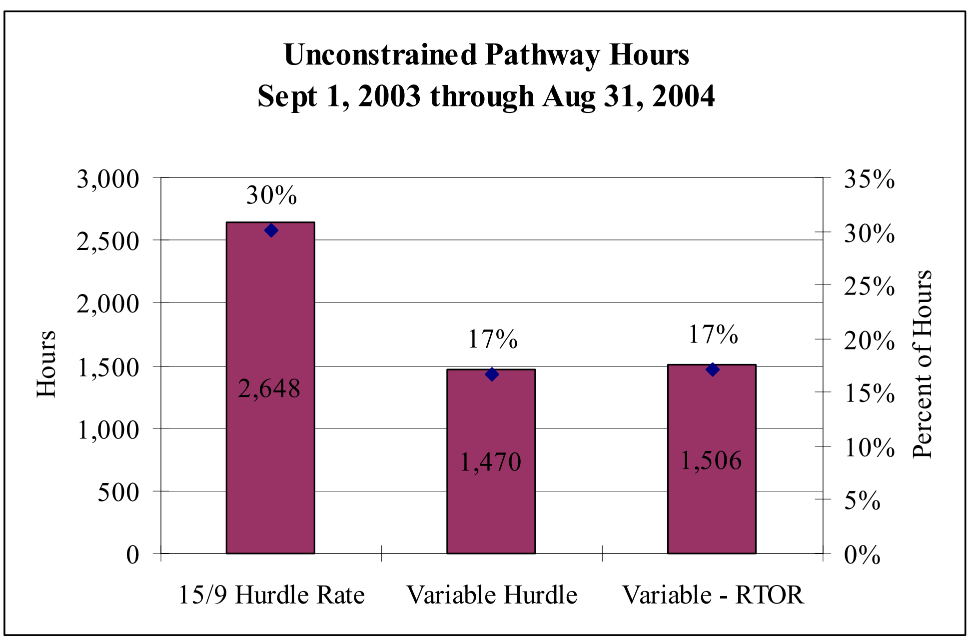


Figure 3.

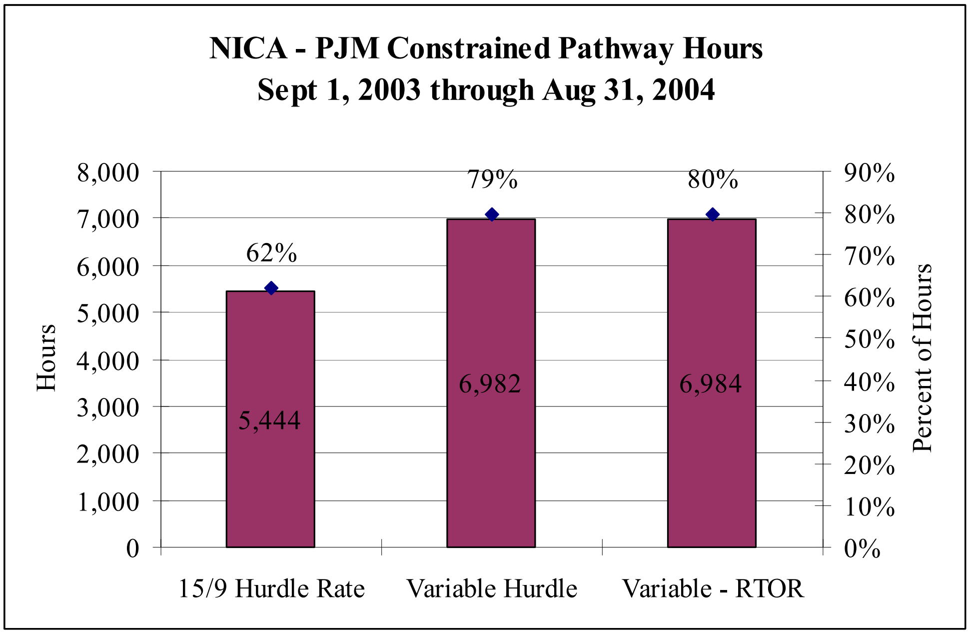
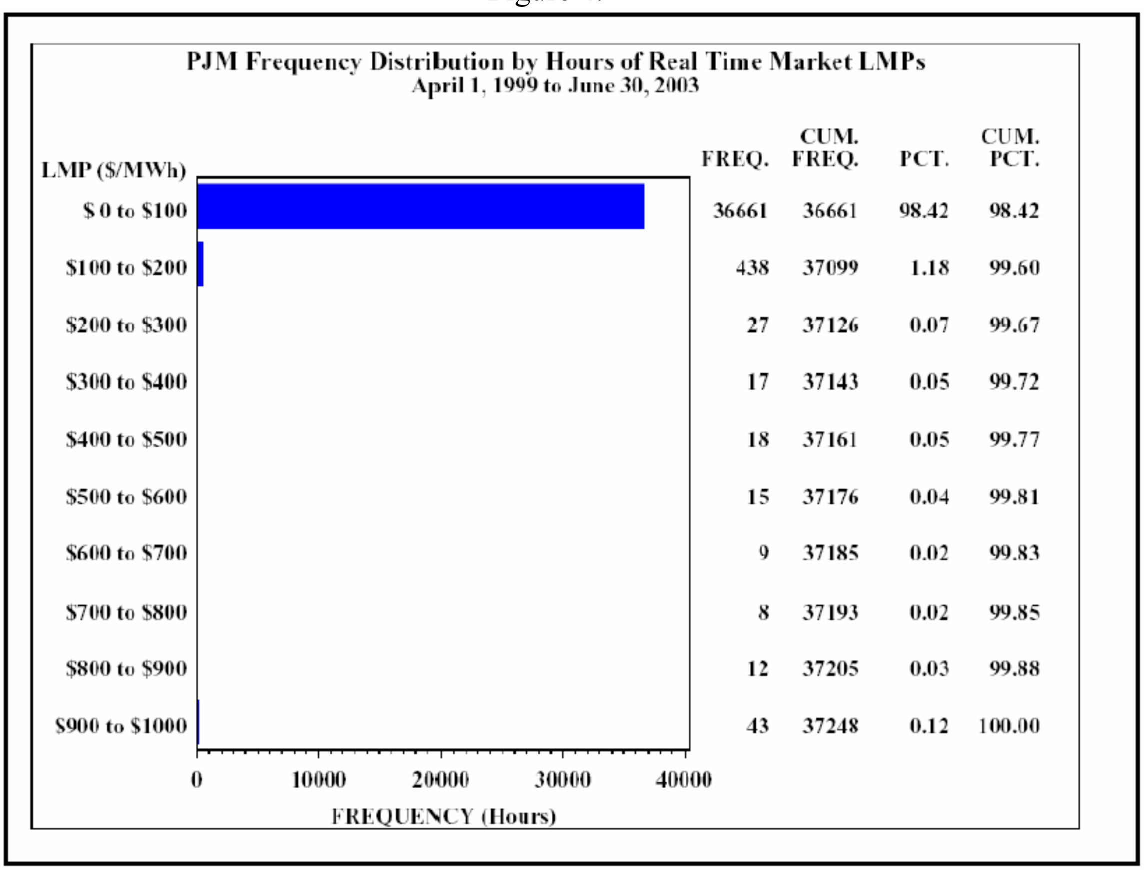


Figure 4.



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $100	36661	36661	98.42	98.42
$100 to $200	438	37099	1.18	99.60
$200 to $300	27	37126	0.07	99.67
$300 to $400	17	37143	0.05	99.72
$400 to $500	18	37161	0.05	99.77
$500 to $600	15	37176	0.04	99.81
$600 to $700	9	37185	0.02	99.83
$700 to $800	8	37193	0.02	99.85
$800 to $900	12	37205	0.03	99.88
$900 to $1000	43	37248	0.12	100.00

Figure 5.

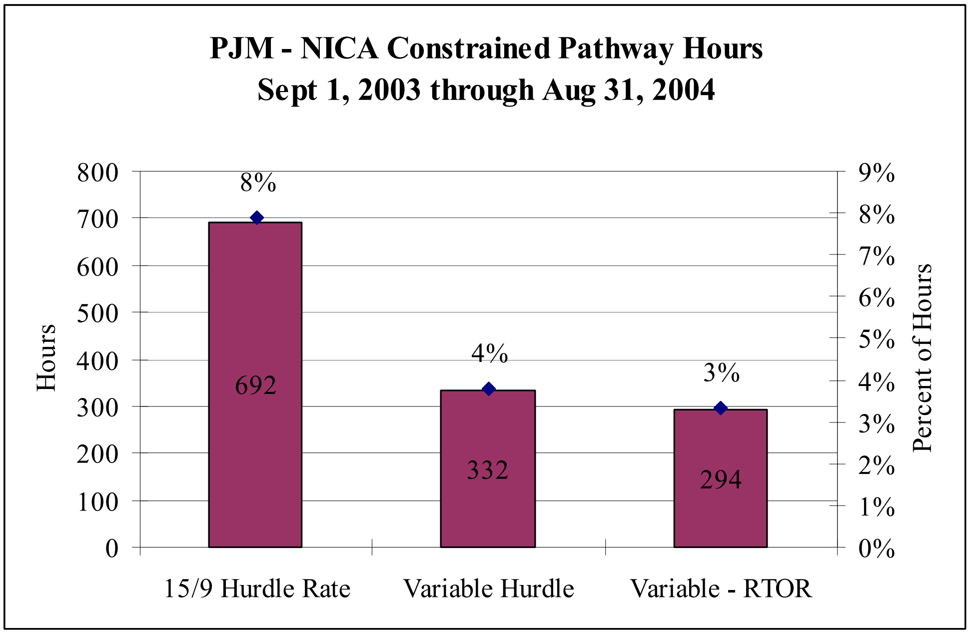


Figure 6.

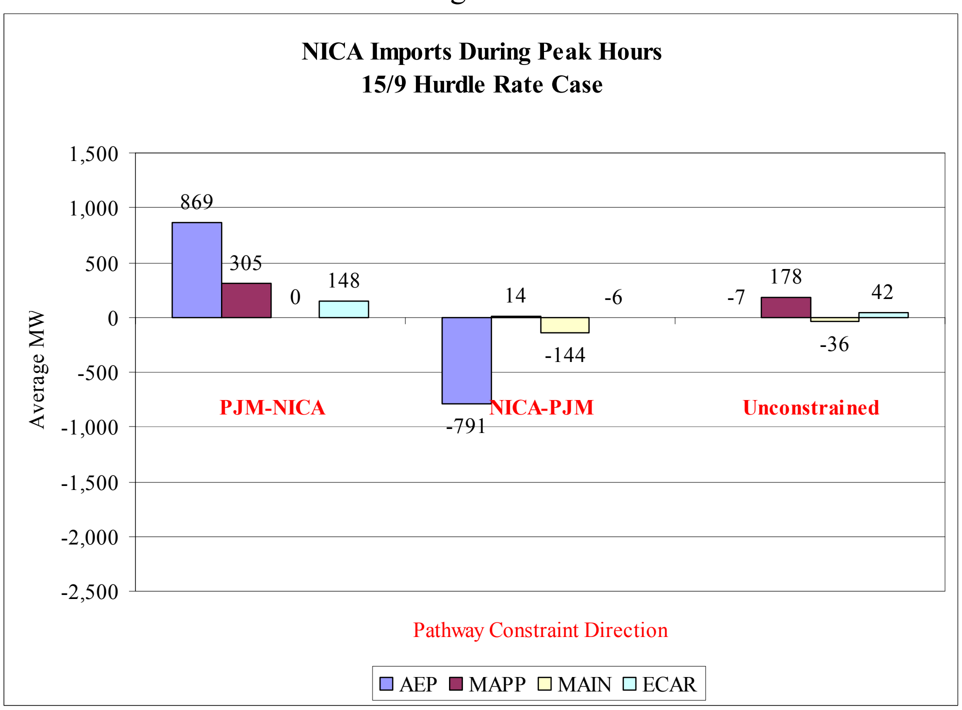


Figure 7.

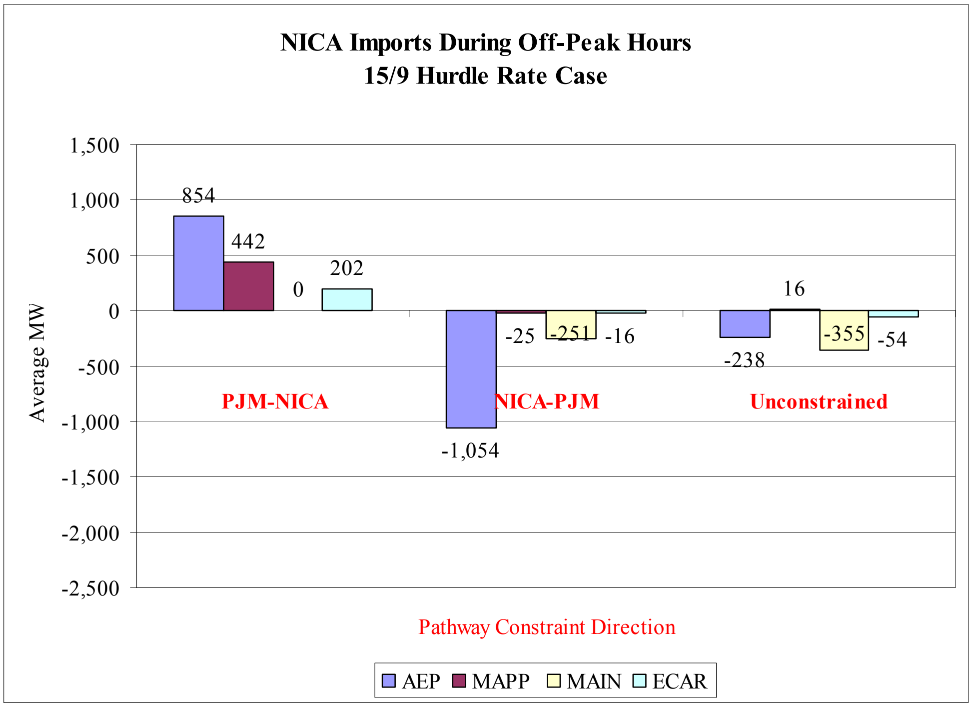


Figure 8.

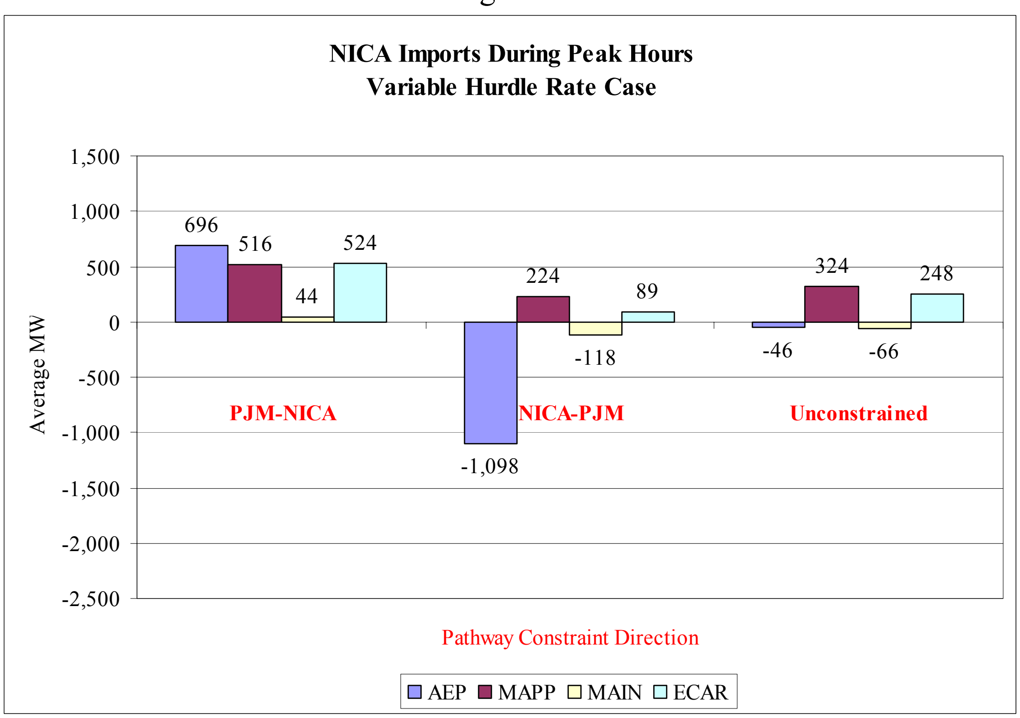


Figure 9.

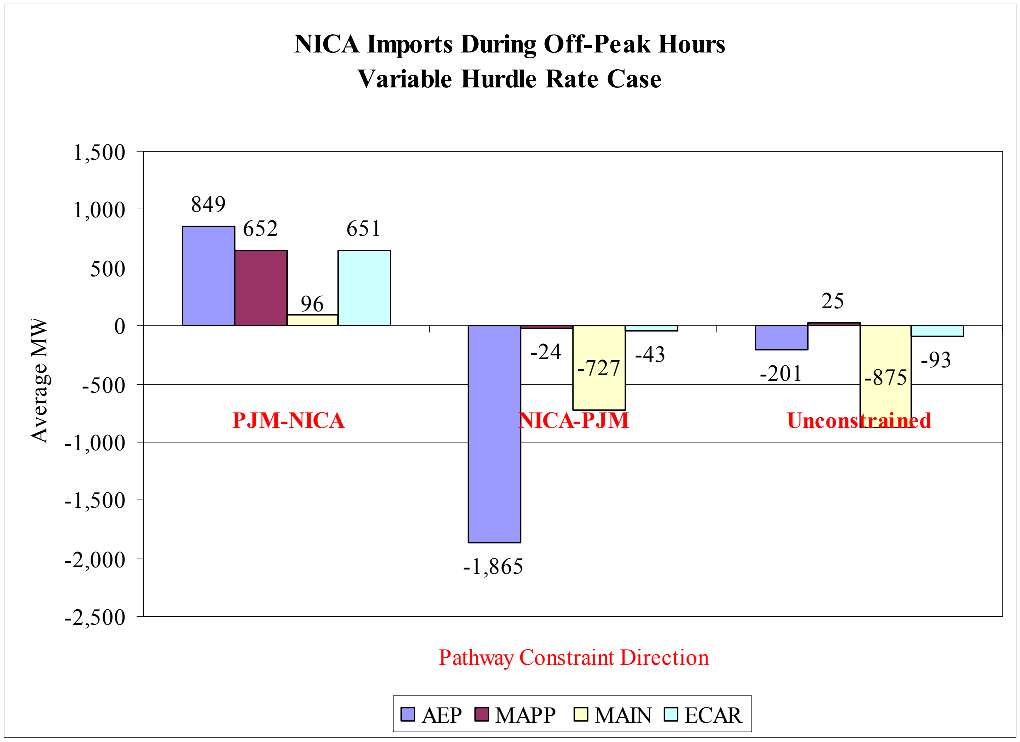


Figure 10.

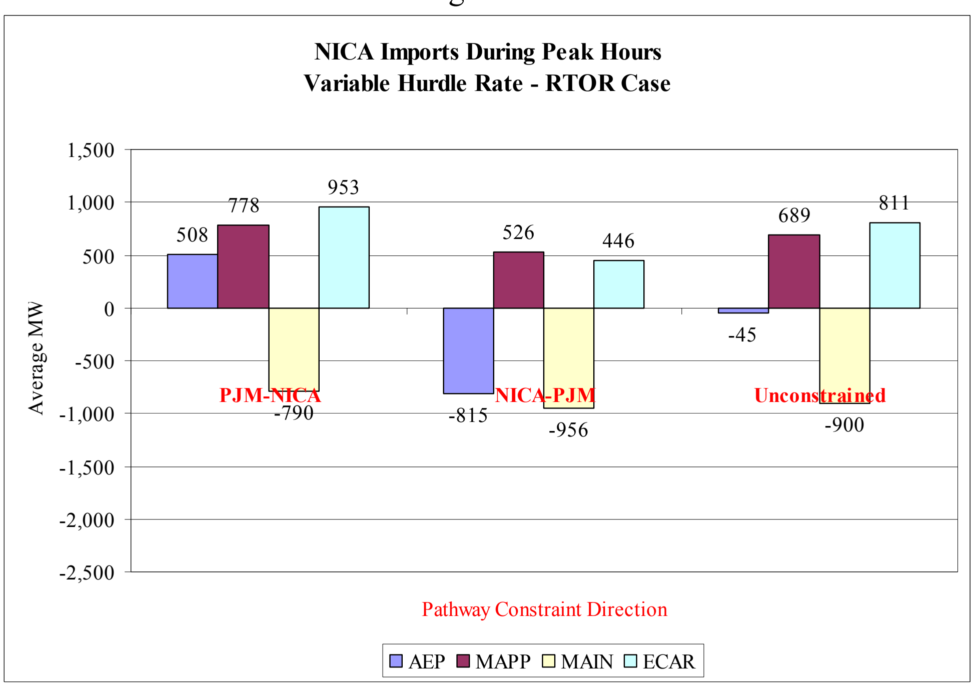
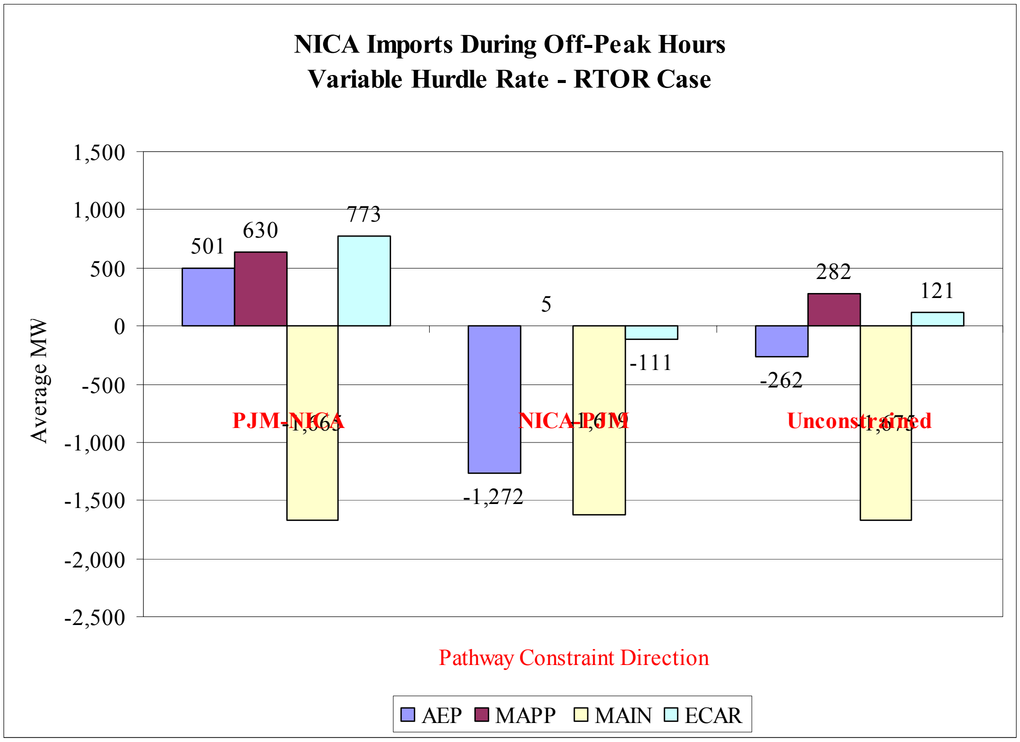


Figure 11.



NICA Imports During Off-Peak Hours
Variable Hurdle Rate - RTOR Case
1,500
1,000
500
0
-500
-1,000
-1,500
-2,000
-2,500
Average MW
501
630
773
5
-111
-1,272
282
121
-262
PJM-NICA
NICA-PJM
Unconstrained
Pathway Constraint Direction
AEP
MAPP
MAIN
ECAR

Figure 12.
ComEd Outer Transmission System

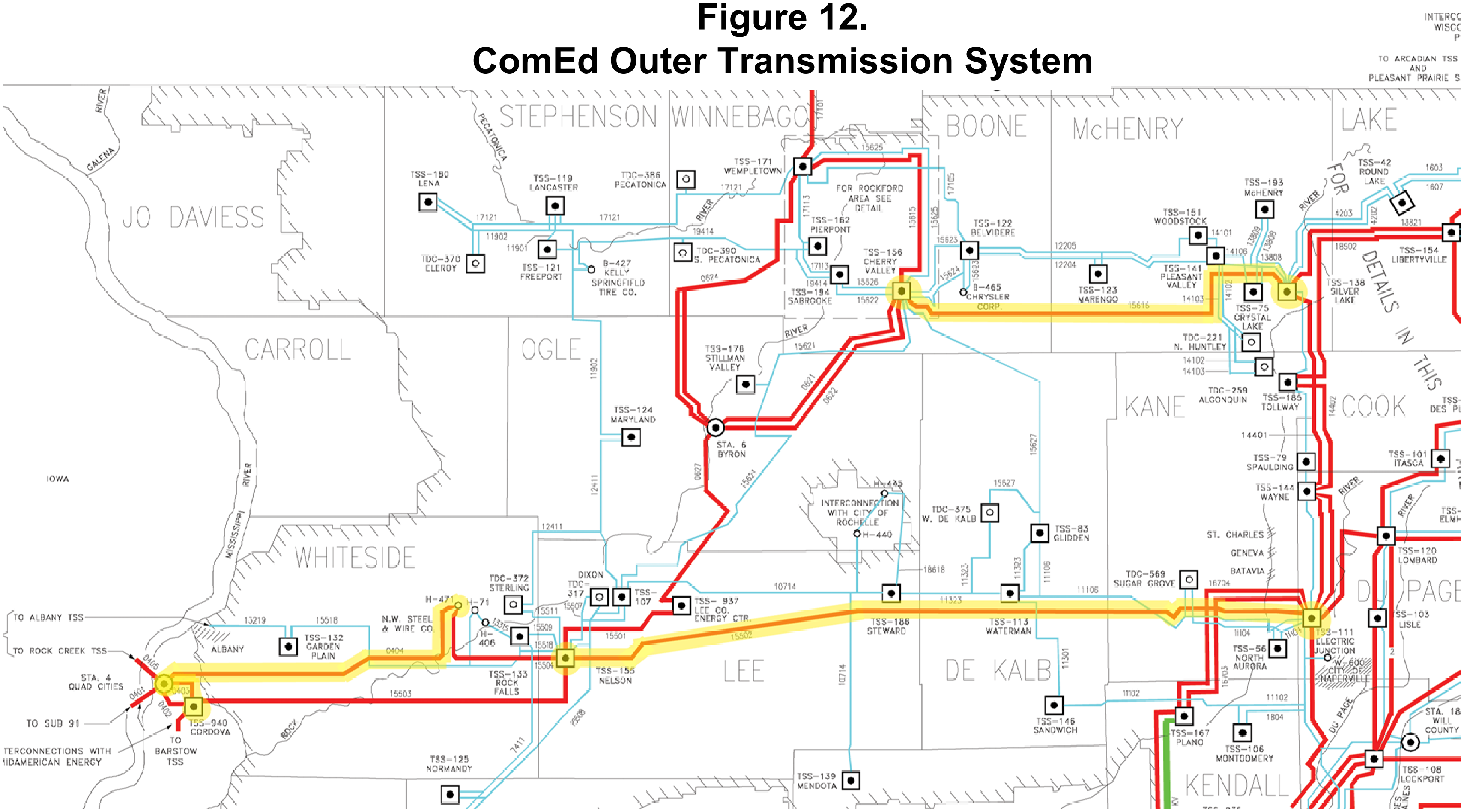


Table 1.

Long Name	Unit Name
BLOOM	BLOOM333
BLOOM	BLOOM334
BLOOM	BLOOM341
BLOOM	BLOOM342
BLOOM	BLOOM344
BRAIDWOOD	BRAIDWO1
BRAIDWOOD	BRAIDWO2
BYRON (COED)	BYRONCO1
BYRON (COED)	BYRONCO2
CALUMET	CALUM311
CALUMET	CALUM312
CALUMET	CALUM313
CALUMET	CALUM314
CALUMET	CALUM321
CALUMET	CALUM331
CALUMET	CALUM332
CALUMET	CALUM333
CALUMET	CALUM341
CALUMET	CALUM342
CALUMET	CALUM343
CALUMET	CALUM344
COLLINS	COLLINS1
COLLINS	COLLINS2
COLLINS	COLLINS3
COLLINS	COLLINS4
COLLINS	COLLINS5
CRAWFORD	CRAWF311
CRAWFORD	CRAWF312
CRAWFORD	CRAWF313
CRAWFORD	CRAWF314
CRAWFORD	CRAWF321
CRAWFORD	CRAWF322
CRAWFORD	CRAWF323
CRAWFORD	CRAWF324
CRAWFORD	CRAWF331
CRAWFORD	CRAWF332
CRAWFORD	CRAWF333
CRAWFORD	CRAWF334
CRAWFORD	CRAWFOR7
CRAWFORD	CRAWFOR8
DRESDEN	DRESDEN2
DRESDEN	DRESDEN3
ELECTRIC JUNCTION	ELECT311
ELECTRIC JUNCTION	ELECT312
ELECTRIC JUNCTION	ELECT313
ELECTRIC JUNCTION	ELECT314
ELECTRIC JUNCTION	ELECT321
ELECTRIC JUNCTION	ELECT322
ELECTRIC JUNCTION	ELECT323

Table 1. (cont.)

Long Name	Unit Name
ELECTRIC JUNCTION	ELECT324
ELECTRIC JUNCTION	ELECT331
ELECTRIC JUNCTION	ELECT332
ELECTRIC JUNCTION	ELECT333
ELECTRIC JUNCTION	ELECT334
FISK	FISK19
FISK	FISK311
FISK	FISK312
FISK	FISK321
FISK	FISK322
FISK	FISK331
FISK	FISK332
FISK	FISK341
FISK	FISK342
JOLIET	JOLIET7
JOLIET	JOLIET8
JOLIET	JOLIE311
JOLIET	JOLIE312
JOLIET	JOLIE313
JOLIET	JOLIE314
JOLIET	JOLIE321
JOLIET	JOLIE322
JOLIET	JOLIE323
JOLIET	JOLIE324
JOLIET	JOLIET96
LA SALLE	LASALLE1
LA SALLE	LASALLE2
LOMBARD	LOMBA311
LOMBARD	LOMBA321
LOMBARD	LOMBA322
LOMBARD	LOMBA331
POWERTON	POWERTO5
POWERTON	POWERTO6
SABROOKE	SABRO311
SABROOKE	SABRO312
SABROOKE	SABRO321
SABROOKE	SABRO322
SABROOKE	SABRO331
SABROOKE	SABRO332
SABROOKE	SABRO341
WAUKEGAN	WAUKE311
WAUKEGAN	WAUKE312
WAUKEGAN	WAUKE321
WAUKEGAN	WAUKE322
WAUKEGAN	WAUKEGA6
WAUKEGAN	WAUKEGA7
WAUKEGAN	WAUKEGA8
WILL COUNTY	WILLCOU1
WILL COUNTY	WILLCOU2

Table 1. (cont.)

Long Name	Unit Name
WILL COUNTY	WILLCOU3
WILL COUNTY	WILLCOU4
BIODYNE PONTAIC	BIODYNE1
JOLIET	JOLILUMP
CHICAGO (CONPOW)	CHICAGC1
CHICAGO (CONPOW)	CHICAGC2
COOK COUNTY	COOKCOU1
COOK COUNTY	COOKCOU2
CRETE ENERGY PARK	CRETEEP1
CRETE ENERGY PARK	CRETEEP2
ELGIN	ELGINGT1
ELGIN	ELGINGT2
ELGIN	ELGINGT3
ELGIN	ELGINGT4
KENDALL COUNTY PROJECT	KENDALC1
KENDALL COUNTY PROJECT	KENDALC2
LEE GENERATING STATION	LEEGENS1
LEE GENERATING STATION	LEEGENS2
LEE GENERATING STATION	LEEGENS3
LEE GENERATING STATION	LEEGENS4
LINCOLN ENERGY CENTER	LINCOLE1
LINCOLN ENERGY CENTER	LINCOLE2
LINCOLN ENERGY CENTER	LINCOLE3
LINCOLN ENERGY CENTER	LINCOLE4
MORRIS COGENERATION PLANT	MORRISC1
RELIANT ENERGY AURORA LP	RELIAUR1
RELIANT ENERGY AURORA LP	RELIAUR2
RELIANT ENERGY AURORA LP	RELIAUR3
RELIANT ENERGY AURORA LP	RELIAUR4
RELIANT ENERGY AURORA LP	RELIAUR5
ROCKFORD (INDOPE)	ROCKFOR1
ROCKFORD (INDOPE)	ROCKFOR2
ROCKFORD II	ROCKFD23
ROCKY ROAD POWER, LLC	ROCKYRP1
UNIVERSITY PARK	UNIVPAR1
UNIVERSITY PARK	UNIVPAR2
UNIVERSITY PARK	UNIVPAR3
ZION ENERGY CENTER	ZIONENC3
ZION ENERGY CENTER	ZIONENC4
ZION ENERGY CENTER	ZIONENC5
SOUTHEAST CHICAGO 1	CALUMET1
SOUTHEAST CHICAGO 2	CALUMET2
SOUTHEAST CHICAGO 3	CALUMET3
SOUTHEAST CHICAGO 4	CALUMET4
SOUTHEAST CHICAGO 5	CALUMET5
SOUTHEAST CHICAGO 6	CALUMET6
SOUTHEAST CHICAGO 7	CALUMET7
SOUTHEAST CHICAGO 8	CALUMET8

Table 2.
Variable Hurdle Rate Matrix

Commitment Hurdle Rate ($/MWh)

Pools	AEP	COMED	CPL	DP&L	DUKE	ECAR	ENTR	FRCC	PJM	MAIN	MAPP	NEPL	NYP	SOU	SPP	TVA	VAC	VEP
AEP		9	9	9	9	9			12	9						9		9
COMED	9					9				9	9							
CPL	9				9											9	9	9
DP&L	9					9												
DUKE	9		9											9		9	9	
ECAR	9	9		9					12	9						9		
ENTR										9	9			9	9	9		
FRCC														9				
PJM	12					12							15					12
MAIN	9	9				9	9				9				9	9		
MAPP		9					9			9					9			
NEPL													13					
NYP									15			13						
SOU					9		9	9								9	9	
SPP							9			9	9							
TVA	9		9		9	9	9			9				9				
VAC			9		9									9				
VEP	9		9						12									

Dispatch Hurdle Rate ($/MWh)

Pools	AEP	COMED	CPL	DP&L	DUKE	ECAR	ENTR	FRCC	PJM	MAIN	MAPP	NEPL	NYP	SOU	SPP	TVA	VAC	VEP
AEP		3	3	3	3	3			6	3						3		3
COMED	3					3				3	3							
CPL	3				3											3	3	3
DP&L	3					3												
DUKE	3		3											3		3	3	
ECAR	3	3		3					6	3						3		
ENTR										3	3			3	3	3		
FRCC														3				
PJM	6					6							9					6
MAIN	3	3				3	3				3				3	3		
MAPP		3					3			3					3			
NEPL													7					
NYP									9			7						
SOU					3		3	3								3	3	
SPP							3			3	3							
TVA	3		3		3	3	3			3				3				
VAC			3		3									3				
VEP	3		3						6									

Table 3.

Variable Hurdle Rate – RTOR Matrix

Commitment Hurdle Rate ($/MWh)

Pools	**AEP**	**COMED**	**CPL**	**DP&L**	**DUKE**	**ECAR**	**ENTR**	**FRCC**	**PJM**	**MAIN**	**MAPP**	**NEPL**	**NYP**	**SOU**	**SPP**	**TVA**	**VAC**	**VEP**
AEP		**6.6**	9	9	9	9			**9.6**	9						9		9
COMED	**6.6**					**6.6**				**6.6**	**6.6**							
CPL	9				9											9	9	9
DP&L	9					9												
DUKE	9		9											9		9	9	
ECAR	9	**6.6**		9					**9.6**	9						9		
ENTR										9	9			9	9	9		
FRCC														9				
PJM	**9.6**					**9.6**							15					12
MAIN	9	**6.6**				9	9				9				9	9		
MAPP		**6.6**					9			9					9			
NEPL													13					
NYP									15			13						
SOU					9		9	9								9	9	
SPP							9			9	9							
TVA	9		9		9	9	9			9				9				
VAC			9		9									9				
VEP	9		9						12									

Dispatch Hurdle Rate ($/MWh)

Pools	**AEP**	**COMED**	**CPL**	**DP&L**	**DUKE**	**ECAR**	**ENTR**	**FRCC**	**PJM**	**MAIN**	**MAPP**	**NEPL**	**NYP**	**SOU**	**SPP**	**TVA**	**VAC**	**VEP**
AEP		**0.6**	3	3	3	3			**3.6**	3						3		3
COMED	**0.6**					**0.6**				**0.6**	**0.6**							
CPL	3				3											3	3	3
DP&L	3					3												
DUKE	3		3											3		3	3	
ECAR	3	**0.6**		3					**3.6**	3						3		
ENTR										3	3			3	3	3		
FRCC														3				
PJM	**3.6**					**3.6**							9					6
MAIN	3	**0.6**				3	3				3				3	3		
MAPP		**0.6**					3			3					3			
NEPL													7					
NYP									9			7						
SOU					3		3	3								3	3	
SPP							3			3	3							
TVA	3		3		3	3	3			3				3				
VAC			3		3									3				
VEP	3		3						6									

Table 4.
NICA Tier-1 Interconnected Control Areas

			NERC Region			
CA	**CA Name**	**Tier**	**ECAR**	**MAIN**	**MAPP**	**Grand Total**
AELC	AESC, LLC - Lincoln Center	**1**		1		1
AEP	AEP Service Corp.	**1**	1			1
ALTE	Alliant Energy - CA - ALTE	**1**		1		1
ALTW	Alliant Energy - CA - ALTW	**1**		1		1
AMRN	Ameren Transmission	**1**		1		1
CILC	Central Illinois Light Co.	**1**		1		1
DELI	DECA, LLC - Lee	**1**		1		1
IP	Illinois Power Company	**1**		1		1
MEC	MidAmerican Energy Company	**1**			1	1
NIPS	Northern Indiana Public Service Corp.	**1**	1			1
WEC	Wisconsin Energy Corporation	**1**		1		1
Grand Total			2	8	1	11

Table 5.
NICA Constrained Facilities
15/9 Hurdle Rate Case

Constrained Facility	**Percent of Hours**
Cherry Valley - Silver Lake 345 kV	51%
Nelson - Electric Junction 345 kV	43%
Quad Cities - Cordova 0403 345 kV	28%
Quad Cities - H 471 345 kV	25%
Byron - Cherry Valley R 345 kV	3%
Byron - Cherry Valley B 345 kV	1%
Total Constrained Hours per Year	**61%**

Table 6.
NICA Constrained Facilities
Variable Hurdle Rate Case

Constrained Facility	Percent of Hours
Cherry Valley - Silver Lake 345 kV	47%
Nelson - Electric Junction 345 kV	37%
Quad Cities - Cordova 0403 345 kV	24%
Quad Cities - H471 345 kV Line	22%
Byron - Cherry Valley R 345 kV	2%
Byron - Cherry Valley B 345 kV	1%
Total Constrained Hours per Year	**56%**

Table 7.
NICA Constrained Facilities
Variable Hurdle Rate - RTOR Case

Constrained Facility	Percent of Hours
Cherry Valley - Silver Lake 345 kV	46%
Nelson - Electric Junction 345 kV	36%
Quad Cities - Cordova 0403 345 kV	26%
Quad Cities - H 471 345 kV	23%
Byron - Cherry Valley R 345 kV	3%
Byron - Cherry Valley B 345 kV	1%
Total Constrained Hours per Year	**55%**