Access Study Initiative Report
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Appendix 1

1. MISO Regional Transmission Planning Process

As a member of the Midwest Independent System Operator (MISO), American Transmission Company, LLC (ATC) participates in MISO's regional transmission planning process. The regional transmission plan developed in the MISO regional transmission planning process is called the MISO Transmission Expansion Plan or MTEP.

New transmission projects proposed by ATC, including an access project, must be coordinated through the MISO regional transmission expansion planning process.

The current MTEP process requires each transmission owner (TO) to submit its current transmission plans with the MISO. MISO then performs an independent assessment of the transmission projects proposed by the transmission owners. As part of this process, MISO ensures that the proposed projects meet identified reliability needs within the MISO system and do not have negative impacts on neighboring transmission systems. As MISO gains experience with the transmission planning process, it will increase its review level of projects as well as identify optimal projects to meet multiple needs across transmission systems within the MISO.

Included here is a description of MISO's next transmission plan, MTEP 06.[1] A list of the objectives of the MISO plan[2] and the key elements[3] to be included in the next MISO transmission plan is also provided.

Description of MTEP 06

The MTEP study provides an independent assessment of the performance of the planned Midwest ISO system, starting with the expansion plans of the MISO TOs and adding projects as may be needed to meet reliability standards. In addition, the MTEP identifies potential regionally beneficial projects that are not required to meet reliability standards (currently referred to as Exploratory Projects). With possible forthcoming changes in cost sharing for transmission upgrades between MISO members and between Regional Transmission Organizations (RTOs), the need to document the needs and alternatives for transmission system upgrades included in the plan will be increasingly important. Therefore, the MTEP 06 will include expanded documentation of system needs for

[1] The description of the MISO MTEP 06 is based on information presented at MISO's July 20, 2005 Advisory Committee meeting. This information is available on the Midwest ISO website: www.midwestiso.org.

[2] The objectives of the MISO MTEP 06 are based on information presented at MISO's July 20, 2005 Advisory Committee meeting. This information is available on the Midwest ISO website: www.midwestiso.org.

[3] Key elements of the MISO MTEP 06 are based on information provided at MISO's August 2, 2005 Market Subcommittee meeting. This information is available on the Midwest ISO website: www.midwestiso.org.

projects included in the plan.

Objectives of MTEP 06

The objectives of the MTEP study are to:

- Determine the adequacy and security of existing transmission system plans of MISO member TOs
- Develop a transmission plan, with documented needs, to provide adequate system reliability
- Track system upgrades to ensure reliability projects, as defined in MTEP 05, are built when needed
- Coordinate transmission plans with neighboring RTO's and non-RTO transmission entities (such as Associated Electric Cooperative Inc. (AECI) and Entergy)
- Identify and recommend transmission system upgrades, which enable more efficient operation of the energy market
- Reduce the cycle time for developing the MTEP to approximately one year
- Seek the development of an optimized transmission plan by:
    - Reviewing the TO's submitted plans and eliminating duplicative transmission plans where appropriate
    - Identifying potential non-transmission solutions to reliability issues, such as demand reductions or new generation additions, where such potential solutions are appropriate
- Provide information relative to expectations of Financial Transmission Right (FTR) coverage under the proposed regional plan.

Key Elements

1. Identify reliability upgrades
2. Identify additional upgrades to reduce congestion
3. Identify expansions of regional scope to enable remote cost effective generation, and renewable resources
4. Identify FTR coverage provided by the proposed Plan

1. Reliable Service

Identification of upgrades needed for reliable and efficient load service

- Network Loads should be able to be served from their Network Resources
- Redispatch and other operating steps are compared to investment costs
- Consolidation of plans into more optimal possibly larger regional expansions if cost effective
- Compare to non-transmission options

2. Enable Market Opportunities

Identification of opportunities to reduce production costs by eliminating constraints to efficient market dispatch from committed resources

- With reliability upgrades in place, search for economic upgrades that are lower cost than projected congestion
- Enable more efficient dispatch than from owned or contract resources

3. Studies of Regional Scope

Identify expansions of regional scope to enable remote cost effective generation and renewable resources

- "Exploratory" expansions that we have been reviewing with stakeholders in select parts of region
- Move analysis to identifying economic as well as reliability benefits and primary beneficiaries
- Initiate such studies in new areas

4. FTR Coverage Information

Identify FTR coverage provided by the proposed Plan

- Scope discussions raised whether MTEP would provide a benchmark test of some type that indicates the level of FTR coverage (allocation) that could be expected with the present plan– MISO believes that it could provide such an indication

A process would need to be developed along the following lines:

- Once the set of plans recommended for the MTEP are developed, an FTR HEDGE model will be developed that matches the topology of the MTEP case
- The most recent existing FTR nomination set will be entered into the HEDGE model, and the allocations reported
- Other possible FTR nomination sets could be tested, with stakeholder input
- One alternative set of interest would align with the MTEP model dispatch supporting the planned upgrades (this set should yield the greatest FTR coverage)
- Information intended to inform the discussion of relationship between regional planning and FTR nomination/allocation process

A Developing Process

- Expected Completion 3rd Q 2006
- Scope document reflects current scope and schedule for the MTEP 06 expansion plan effort of the Midwest ISO
- Expected that all elements of this plan will be completed and included in the MTEP 06 report to the Board of Directors
- If MISO staff determines with ongoing input and review by stakeholders that there will need to be a significant change in scope, schedule, or methodology, staff will report such changes to the Planning Subcommittee and the Advisory Committee

2. MISO Transmission Cost Allocation and Planning Activities

a. Regional Expansion and Criteria Benefits Task Force (RECB)

The RECB task force has been created by MISO and its stakeholders to consider alternatives for regional cost allocation of new transmission facilities. The group has been in existence since early 2004 and has been evaluating several approaches to regional cost allocation since that time.

MISO is currently planning to make a filing to the Federal Energy Regulatory Commission (FERC) for a regional cost allocation method for new transmission facilities in mid-September 2005. (Presently there is no required date when MISO must make this filing.) MISO originally intended to file regional cost allocation proposals in August 2004 and then again in May 2005, but could not reach consensus with the stakeholder group. Although a regional cost allocation methodology is not currently in place for MISO, it is likely that a regional cost allocation for new transmission facilities will be in place before an access project receives regulatory approval and is placed in service.

The following is a discussion of the issues that the RECB group is considering that may impact cost allociation for a future transmission access project. At the end of the discussion of issues a calculation is included that shows an estimated cost ATC customers would be responsible for under each proposed access project should current RECB proposals under discussion be adopted.

Issues that RECB is addressing and current status:

Transmission projects that may receive regional cost allocation

RECB currently separates new transmission projects into three categories:

- Reliability projects
- Regionally beneficial (economic) projects
- Generator interconnection projects

The cost allocation under discussion in the RECB task force is limited to reliability and generator interconnection projects. Reliability projects are generally defined as transmission built primarily to meet North American Electric Reliability Council (NERC) reliability criteria, load growth needs or individual state reliability requirements. The RECB task force intends to address regional cost sharing for economic projects in the future. These discussions have not yet begun. Any specific cost sharing for economic transmission projects would be subject to proposed future MISO tariff provisions and FERC policy decisions.

Current Proposals for Regional Cost Sharing

The current proposals for regional cost allocation for reliability projects have changed frequently and are not yet finalized. The following elements for cost allocation have been discussed over the last several months. While still under consideration, none of these elements have achieved consensus within the RECB task force at this time.

Regional Component: postage stamp charge

Allocations:

Regional cost allocation would be paid by all MISO load-serving entities and would apply to all reliability projects that have a project cost of $5 million or greater.

> Projects with voltages < 345 kV - 20% of the project cost is allocated to the regional component
> Projects with voltages $\geq$ 345 kV - 30% of the project cost is allocated to the regional component

Under the current proposal, regional costs would be allocated to load serving entities within MISO on a load ratio share basis. This component is referred to as a "postage stamp" charge.

There is currently no consensus within RECB that a postage stamp charge will be a component in the final cost allocation methodology. Recent discussions have suggested that the allocation percentages of the regional cost components should be reduced to a level of 10-20% of project costs instead of 20-30%. A new proposal using these lower levels of postage stamp allocation has not yet been proposed.

Local Component: license plate charge

The local component would be paid by the load serving entities within the transmission pricing zone in which the project is proposed.

> < 345 kV - 30% of the project cost is allocated to the local component

> $\geq$ 345 kV - 20% of the project cost is allocated to the local component

Recent proposals during RECB discussions have suggested eliminating this component, leaving only regional and sub-regional components.

Sub-Regional Component: transmission loading factors

Under the current RECB proposal, all costs that are not allocated as part of a regional cost component would be allocated to load serving entities that receive benefits from a new transmission project as determined by a load flow analysis using line outage distribution factors (LODF).[4]

A sample calculation of costs for the access alternatives has been included in Table 1A below. Using the current cost allocation methodologies under discussion by the RECB task force, this analysis demonstrates how costs could be allocated for projects that receive regional cost allocation.

3. Level Playing Field Issue

During the RECB task force meetings, certain stakeholders have suggested that the transmission systems within MISO are not all at the same level of quality. These stakeholders have advocated delaying regional cost sharing of new transmission projects until certain "deficient" transmission systems meet a minimum standard for level of service (i.e. build sufficient transmission infrastructure to catch up to the allegedly more "robust and rigid" transmission systems). Several approaches to develop criteria to determine when all systems would be at an acceptable level of quality have been proposed.

Thus far the most likely approach that RECB has developed to address this issue is to either select a point in time after which all projects will be eligible for cost sharing or to exclude certain known "committed" projects from regional cost sharing.

It is likely that an access project would be implemented far enough in the future that the level-playing field issue will not be a factor. It is unlikely that consensus will be reached at the stakeholder level on this issue and ultimately MISO and FERC will develop a policy to address this issue.

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[4] LODF is a measure of the redistribution of electric power on remaining transmission lines caused by an outage of a given transmission line. The LODF is expressed in percent of the pre-contingency electrical loading on the line placed on outage. Example: Before the outage of line B, its flow is 30 MW. After the outage of line B, the flow on line A increases by 10 MW due to the redistribution of flows from B. LODF = Effect of loading on line A for an outage of line B = (Increase in flow on line A due to an outage of line B)/(Pre-contingency flow on line B)*100% = 10MW/30MW*100%=33.3%.

The cost allocation is based on taking each of the Access alternative projects out of service individually and then calculating how this impacts the LODFs on all of the other lines throughout MISO. The cost allocation is based on the sum of the LODFs for all of the lines within ATC relative to all of the lines within MISO. Typically the closer another line is to the line placed in outage and the more "parallel" it is, the higher the LODF. LODFs below a certain threshold are not included in the sum.

4. Cross Border – Inter-RTO Transmission Cost Allocation

Pursuant to FERC requirements in its November 24, 2004 Order in Docket EL02-111,[5] MISO and PJM filed a compliance filing in May 2005 that proposed a methodology to share costs of new transmission facilities that provide benefits to both RTOs (Docket No. ER05-6).[6] FERC is expected to act on this filing later this year.

The proposed methodology for inter-RTO cost sharing between PJM and MISO for new transmission facilities is as follows:

- May 2005 Compliance filing addresses baseline reliability projects only
- A second filing to address economic projects is scheduled to be made by 6/01/2006
- Projects that are eligible for inter-RTO cost sharing must meet the following thresholds:
    - $10 million minimum revenue requirement assigned to the other RTO
    - A minimum level cost sharing threshold where 5% or more of the project cost must be assigned to the other RTO, according to a load flow analysis specified by the Joint Operating Agreement (JOA) between MISO and PJM
    - Would only apply to projects in-service ***after*** 12/31/07
    - There would be no inter-RTO cost sharing for ATC's Arrowhead-Weston and AEP's Wyoming-Jackson's Ferry projects

The outcome of the cross-border cost allocation may impact the cost sharing of the ATC Access project. If the project is accepted in the joint PJM-MISO plan in the future and is demonstrated to provide benefits to PJM, a portion of the access project costs would be allocated to PJM. An estimate of cost allocations across both RTOs is included in Table 1A.

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[5] In Docket No. EL02-111, FERC eliminated regional through and out rates between MISO and PJM. *Midwest Independent Transmission System Operator, Inc., et al.*, 104 FERC ¶ 61,105, *order on reh'g*, 105 FERC ¶ 61,212 (2003). A stakeholder process to develop transitional lost revenue recovery mechanisms was subsequently implemented and settlement judge procedures resulted in an agreement, entitled "Going Forward Principles and Procedures" (Agreement). The Agreement established a framework to guide the parties in the development of a long-term transmission pricing structure for the MISO-PJM footprint. Two competing pricing proposals were submitted to FERC, and on November 18, 2004, the Commission issued an order in which it adopted, among other things, a license plate rate design. *Midwest Independent Transmission System Operator, Inc., et al.*, 109 FERC ¶ 61,168 (2004). To deal with the potential problem of license plate rates causing local load to bear the costs of new facilities and expansions without receiving commensurate benefits, the Commission directed MISO, PJM and their transmission owners to develop and file a proposal for the allocation of cross-border costs to the customers receiving the benefit in one RTO for new transmission facilities built in the other RTO. *Id.* at ¶ 60.

[6] *See* Docket No. ER05-6-023, et al., Joint Compliance Filing, May 17, 2005.

Example of Access Project Capital Cost Allocation under the Current RECB and Cross Border Proposals

The table below indicates how the cost of ATC's alternative access projects would be allocated if the current RECB proposal were implemented. The MISO and MISO & PJM columns represent the RECB cost allocation proposal as applied to a (1) MISO-only area, if the project receives regional cost allocation within the MISO only and (2) the combined MISO and PJM area, if a project receives regional cost allocation within MISO and also inter-RTO cost allocation in PJM.

Table 1A – Access Project Costs Allocated to ATC under Regional Cost Allocation and Inter-RTO Cost Allocation

		Net ATC Project Cost[a]		**ATC Percent of Project[b]**	
Project	Project Costs (2005 $)	MISO	MISO & PJM	MISO	MISO & PJM
Low Voltage	$33,000,000	$13,648,663	$10,535,705	41%	32%
Byron - NMA	$186,000,000	$117,742,311	$70,106,867	63%	38%
Salem - NMA	$352,000,000	$160,703,801	$114,847,632	46%	33%
Paddock - Rockdale	$69,000,000	$47,372,601	$32,568,335	69%	47%
Prairie - Columbia	$640,000,000	$268,398,731	$214,819,388	42%	34%

a - Cost allocation to ATC:
(1) Regional cost allocation within MISO
(2) Regional cost allocation within MISO and Inter-RTO cost allocation within PJM

b - Percentage of cost allocation to ATC
(1) Regional cost allocation within MISO
(2) Regional cost allocation within MISO and Inter-RTO cost allocation within PJM

The two tables below are a more detailed representation of the summary table above.

					Midwest ISO Only			
Project	Capital Costs (2005 $)	Voltage	Allocation Factor		ATC Cost Allocation[c]		MISO Cost Allocation[d]	
			Regional	Subregion	Regional	Subregion	Regional	Subregion
Low Voltage	$33,000,000	161 kV	20%	80%	12%	49%	88%	51%
Byron – NMA	$186,000,000	345 kV	30%	70%	12%	85%	88%	15%
Salem – NMA	$352,000,000	345 kV	30%	70%	12%	60%	88%	40%
Paddock - Rockdale	$69,000,000	345 kV	30%	70%	12%	93%	88%	7%
Prairie - Columbia	$640,000,000	345 kV	30%	70%	12%	55%	88%	45%
Source			RECB Proposal		LRS	LODF		

c - ATC percentage allocation of total regional and subregional project costs
d - Percentage allocation of total regional and subregional project costs to others within MISO

Table 1C – Assumptions Used for Regional and Subregional Cost Allocations within MISO and PJM

					Midwest ISO and PJM			
Project	Capital Costs (2005 $)	Voltage	Allocation Factor		ATC Cost Allocation[e]		Other Cost Allocation[f]	
			Regional	Subregion	Regional	Subregion	Regional	Subregion
Low Voltage	$33,000,000	161 kV	20%	80%	10%	37%	90%	63%
Byron – NMA	$186,000,000	345 kV	30%	70%	10%	49%	90%	51%
Salem – NMA	$352,000,000	345 kV	30%	70%	10%	42%	90%	58%
Paddock – Rockdale	$69,000,000	345 kV	30%	70%	10%	63%	90%	37%
Prairie – Columbia	$640,000,000	345 kV	30%	70%	10%	44%	90%	56%
Total	$1,280,000,000							
Source			RECB Proposal		LRS	LODF		

e - ATC percentage allocation of total regional and subregional project costs
f - Percentage allocation of total regional and subregional project costs to others within MISO and PJM

Appendix 2
Transmission Planning Activities in Other States

ATC coordinates its transmission planning activities with neighboring states as well as with MISO. This section discusses current transmission planning activities in states surrounding Wisconsin.

Illinois

Commonwealth Edison (Com Ed):

ATC is regularly in discussions with Com Ed to coordinate transmission planning activities and projects. Most recently ATC worked extensively with Com Ed to plan and construct the Wempletown–Paddock line, which began operations in summer 2005.

Statewide studies: ATC is not aware of any current active statewide transmission studies in Illinois.

Iowa

Interstate Power & Light (Alliant) Study of Eastern Iowa:

The transmission system of eastern Iowa is comprised mainly of 161 and 69 kV facilities, with a few facilities rated at 345, 115, and 34.5 kV.

Beginning in the latter part of the 1990's with the advent of the open access energy market, this area of the transmission system began to realize additional stresses as regional power flow patterns have increased from the south and southeast directions to the north and northwest.

Alliant, in conjunction with MISO, has initiated a transmission planning study of eastern Iowa. A transmission planning study in this region will address the following transmission issues:

- Identify bulk transmission (> 100 kV) needs to support the sub-transmission system for load serving requirements,
- Identify reliability concerns on the bulk transmission system due to the impacts of power transfers, and
- Address key operational issues in the region that have developed over the last few years.

The goal of the transmission study effort for eastern Iowa is two-fold:

- With thorough and comprehensive analysis, gain an understanding of the interactions of the transmission system with respect to varying load and market

levels and their impacts on reliability for the near-term and long-term planning horizons.

- Develop a responsible, comprehensive and least-cost transmission plan for this area that will address the needs of the transmission system to accommodate both the near-term and long-term planning horizons.

Minnesota

Several transmission planning activities are on-going in Minnesota. They include:

MISO Exploratory
Rochester MN
CapX 2020

Further discussion and details for these activities are included here.

MISO Exploratory - The objective of the Iowa-Southern Minnesota Exploratory Study (ISMNEX) is to develop a high-level exploratory transmission plan, which provides increased transmission capability to facilitate the development and integration of wind generation resources in this area and addresses regional reliability issues. The study results will provide direction to MISO and transmission providers in the region on how to best develop the transmission system in this region. This exploratory study will not attempt to resolve underlying system issues, but will develop an understanding of what bulk transmission improvements would be required to deliver significant amounts of generation. This study is a continuation of the MTEP-03 exploratory study. This study is an open and collaborative planning process with MISO staff, wind developers, wind advocates, utility planners, and state regulatory staff members in the stakeholder/study group.

Rochester MN – The objective of this study is to define the transmission deficiencies in the SE MN and SW WI regions as determined by the study participants. The study will determine possible SE MN and SW WI regional transmission solutions as defined by the study participants to address the deficiencies. Work also includes the following: perform baseline AC Contingency Checking (ACCC), Load Flow, voltage profile, and stability analyses of the existing transmission system in SE MN and SW WI. These analyses will be used to validate the model and will become the baseline to evaluate and quantify transmission system improvements.

CapX 2020 - Minnesota's electric transmission infrastructure—a network of high voltage transmission lines of 230 kilovolts and higher—requires major upgrades and expansion over the next 15 years to support Minnesota's growing demand for electricity. To ensure the backbone transmission system is developed and available to serve these growing needs, Minnesota transmission-owning utilities initiated the CapX 2020 project. Great River Energy, Minnesota Power, Otter Tail Power Company and Xcel Energy jointly formed CapX 2020 in the summer of 2004; Minnkota Power Cooperative, Missouri River Energy Services and Southern Minnesota Municipal Power Agency

(SMMPA) subsequently joined this effort. "CapX 2020" is an abbreviation for "Capital Expenditures by the Year 2020".

CapX 2020's mission is to:

- Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region; and
- Work to create an environment that allows these projects to be developed in a timely, efficient manner, consistent with the public interest.

Wisconsin

Dairyland Power Cooperative:

1) The study evaluates the long term load serving requirements of the transmission system serving La Crosse, Wisconsin. A major outage for the La Crosse area would be an outage of Genoa-La Crosse-Marshland- 161 kV, which causes the overload of the Genoa-Coulee 161 kV line. Another factor is that the Genoa-Alma 161 kV line, the first 161kV line built by DPC, is nearing the end of its useful life. This study is a subset of the SE Minnesota/SW Wisconsin study led by Rochester Public Utilities (RPU). Correcting the Genoa-Coulee 161 kV overload is also a Mid-Continent Area Power Pool (MAPP) Design Review Subcommittee (DRS) requirement for approval of the 150 MW power transfer from Wisconsin Public Service (WPS) to DPC. In parallel to this study, DPC, Xcel, and ATC will be performing a study of the Tomah, WI area. The primary alternative to enhancing load-serving capability to Tomah is a new 161 kV line from Monroe County to Council Creek (Tomah) and a 161-138 kV transformer at Council Creek. All alternatives examined to address La Crosse area load-serving issues will include a sensitivity to this facility to ensure that the plans are properly coordinated.

2) Determine the transmission impacts of converting Monroe County-Council Creek 69 kV circuit to a 161/69 kV double circuit line, paying particular attention to the following:

    - Develop a responsible, comprehensive and least-cost transmission plan for this area that will address the needs of the transmission system to accommodate both the near-term and long-term planning horizons.
    - The need for additional transformer capacity at Monroe County and/or Council Creek (COC).
    - Impacts to the ATC transmission system east of COC.
    - Impacts to the DPC and Xcel transmission systems west of Monroe County.
    - Impact to Hillsboro-Hilltop 69 kV line (under high transfer).

- Relaying of the Monroe County-Council Creek-Oakdale (OAK) 69 kV circuit.
- Impact on Eau Claire-Arpin Op Guides.

Michigan

Capacity Need Forum

On October 14, 2004, the Michigan Public Service Commission (MPSC) initiated on its own motion an investigation into future capacity requirements (Case No. U-14231). A final report in this case is expected by January 1, 2006.

The Capacity Need Forum (CNF) was created as a collaborative industry-wide process to assess the projected need for electrical generating capacity in Michigan over the short-, intermediate- and long-term future.

The work for the CNF is being accomplished by several work groups. ATC participates in the Transmission and Distribution work group, which is responsible for compiling information on the existing transmission capacity. The group is also responsible for identifying any plans for immediate increase in capacity and to identify potential transmission investment options that can be used if additional electric capacity is needed. The group has been meeting and gathering information and will report its findings in its final report.

Transmission Siting Processes in Other States

This section is a discussion of the transmission siting processes in the states surrounding Wisconsin (Illinois, Iowa, Michigan and Minnesota).[1]

ILLINOIS TRANSMISSION SITING PROCESS

- Generally, if the proposed electric line leaves the utility's certificated area, is of sufficient size to be reviewed in any future rate cases, or if the utility foresees the possibility of requesting eminent domain, a certificate application will be filed by the utility and reviewed by the ICC.
- If the proposed line will exist in the utility's already certificated area, then the utility can treat the line as an extension of its current facility, which does not require a certificate.

[1] The information included in this section has been obtained from an Organization of MISO States (OMS) study on transmission siting processes within the MISO footprint prepared by Edison Electric Institute (EEI). The full study is available on the OMS website: www.misostates.org.

Steps Required

1. Meet Environmental and Legal Requirements
2. File Application for Certificate of Public Convenience and Necessity
3. File for Construction Authorization and Authority to use Eminent Domain

1. Meet Environmental and Legal Requirements

- Obtain permission from the Department of Natural Resources (DNR) to establish a route near any parks, forest preserves, national forests, wildlife refuges, and scenic areas
- Complete the Endangered Species Consultation with the DNR
- Obtain an Agricultural Impact Mitigation Agreement with the Illinois Department of Agriculture
- Summarize required acres of land by zoning type
- Obtain river, stream and lake crossing permits from the U.S. Army Corps of Engineers
- Obtain approval for any involved historical or archaeological areas from the Illinois Historical Agency
- Provide data as required by the Farmland Preservation Act
- Specify steps to be taken to restore and repair any land on which the line will be constructed
- Identify any other utilities whose facilities may be adversely affected by the construction process

2. File Application for Certificate of Public Convenience and Necessity

- There is no formal application: the filing must include whatever documentation is necessary to prove that the applicant has met all requirements and obtained all permits
- Three criteria must be met: the line must be necessary to provide adequate, reliable and efficient service; the applicant must be capable of managing and supervising the construction of the line; and the applicant must be able to finance the proposed construction
- Illinois Commerce Commission holds a public hearing to determine if the relevant criteria have been met
- If all criteria are met, then the ICC has the authority to issue the certificate
- If a certificate is not issued, the applicant has the right to request a rehearing or appeal the decision to the appellate and supreme courts

- The review process can take between three and eighteen months, but is typically completed in twelve months

3. File for Construction Authorization and Authority to Use Eminent Domain

IOWA TRANSMISSION SITING PROCESS

Informational Meeting

- Must be held if more than 1 mile of property is affected
- Must occur at least 30 days before petition is filed
- Notice must be published no less than three weeks before meeting

File Petition with PUC

Petition Instructions:

- Exhibit A. A legal description of the route. The description shall include the name of the county, the maximum and nominal voltages, the beginning and ending points of the line, and whether the route is on public, private, or railroad right-of-way. In the case of the multi-county projects, the description shall identify all counties involved in the total project and any termini located in other counties.
- Exhibit B. A map showing the route of the line drawn with reasonable accuracy considering the scale. The map may be to any scale appropriate for the level of detail to be shown, but not smaller than one inch to the mile.
- Exhibit C. Technical information and engineering specifications describing typical materials, equipment and assembly methods as specified on forms provided by the board.
- Exhibit D. The exhibit shall consist of a written text that includes the following:
    - An allegation, with supporting testimony, that the line is necessary to serve a public use.
    - If the route or any portion thereof is not near and parallel to railroad right-of-way or along division lines of the lands, according to government surveys, a showing of why such parallel routing is not practicable or reasonable.
- Exhibit E. This exhibit is required only if the petition requests the right of eminent domain. It shall consist of a map of the route showing the location of each property for which the right of eminent domain is sought.
- Exhibit F. The showing of notice to potentially affected parties.
- Exhibit G. The affidavit on the holding of an informational meeting. Copies of the mailed notice letter and the published notice(s) of the informational meeting

shall be attached to the affidavit. This exhibit is required only if an informational meeting was conducted.

Staff Review

- Petitioner must correct any defects in petition or design based on staff review.

If No Filed Objections or Eminent Domain

- Notice is published for two weeks in affected counties listing program and inviting comments
  - Objections must be received no later than 20 days after second publication date
  - If no objections received, franchise issued
  - If objections received, evidentiary hearing is held (see below)

In Case of Filed Objections or Eminent Domain

- Evidentiary hearing held
  - Notice must be published for two consecutive weeks before hearing in affected county
  - Hearing held not less than 30 days after last notice
  - If line is more than one mile long, hearing is held in county of mid-point
- Decision rendered after hearing (no time limit mentioned in regulations)

MICHIGAN TRANSMISSION SITING PROCESS

File plan with MPSC

- Applies to utilities with >50,000 residential customers
- Must include: location, size of transmission lines to be constructed within 5 years of beginning construction, copies of bulk power transmission information, any additional information required in MPSC rule/order

Apply for Certificate of Public Convenience & Necessity with MPSC

- Applies to utilities with >50,000 residential customers
- Must include: planned construction date, detailed description of planned line, its route, and its expected configuration and use, a description and evaluation of one or more planned routes and a statement why proposed route was selected, any zoning ordinance violations, info. supporting need of line, including no. of wholesale users, estimate of private benefits to applicant and any beneficiaries,

estimate of quantifiable and non-quantifiable public benefits, info. regarding potential effects on health and safety, summary of all comments received at public meetings and applicant's responses, info. that line will comply with all applicable state and federal environmental standards, laws, and rules

- Cannot begin construction until MPSC issues a certificate of public convenience and necessity

  -or-

Contested Case

- Conducted by MPSC on each application
- May require utility to hire consultants chosen by MPSC to assist in evaluation

Decision Made

- No later than 1 year after filing date, will grant proposed route, alternative route, or reject application
- May condition approval upon utility taking steps to further assure public safety and convenience

Application Granted if Following Conditions Met:

- Quantifiable and non-quantifiable benefits justify construction, proposed or alternative route is reasonable and feasible, line does not pose an unreasonable threat to public health/safety, utility has accepted conditions contained in acceptance
- If construction does not begin within 5 years of certificate, certificate is void

MINNESOTA TRANSMISSION SITING PROCESS

Full Review Siting Process:

- Applies to those transmission lines over 100 kV that do not qualify for Alternate Review (see Alternative Siting Process slide)

Two Requirements:

1. Certificate of Need
2. Routing Permit

1. Certificate of Need Process

- No less than 45 days before filing an application, a proposer may request exemption from filing requirements. PUC responds within 30 days, granting or denying exemption.
- Proposer files application with the PUC.

- PUC determines completeness within 30 days.
- PUC refers contested case to Administrative Law Judge (independent agency).
- PUC conducts public information meetings.
- ALJ convenes pre-hearing conference to set schedule relating to intervention requests, pre-filed testimony, rebuttal testimony, public and evidentiary hearings and location, submittal of environmental review documents, post-hearing briefs, reply briefs, and exceptions. The Minnesota Department of Commerce conducts discovery and prepares the state's case.
- Hearings held.
- Report and recommendations of ALJ go to PUC.
- PUC conducts decisional hearing.

2. Routing Permit Process

Two Requirements:

A. Application
B. Environmental Impact Study

A. Application Process

- An application for a route permit for a high voltage transmission line shall contain the following information:
    - At least two proposed routes for the proposed high voltage transmission line and identification of the applicant's preferred route and the reasons for the preference;
    - A description of the proposed high voltage transmission line and all associated facilities including the size and type of the high voltage transmission line;
    - Identification of land uses and environmental conditions along the proposed routes;
    - Cost analysis of each route, including the costs of constructing, operating, and maintaining the high voltage transmission line that are dependent on design and route;
    - A listing and brief description of federal, state, and local permits that may be required for the proposed high voltage transmission line;
    - A copy of the Certificate of Need or the certified HVTL list containing the proposed high voltage transmission line or documentation that an application for a Certificate of Need has been submitted or is not required; and
    - Environmental information. An applicant for a site permit or a route permit shall include in the application the following environmental

information for each proposed site or route to aid in the preparation of an environmental impact statement:

- A description of the environmental setting for each site or route;
- A description of the effects of construction and operation of the facility on human settlement, including, but not limited to, public health and safety, displacement, noise, aesthetics, socioeconomic impacts, cultural values, recreation, and public services;
- A description of the effects of the facility on land-based economies, including, but not limited to, agriculture, forestry, tourism, and mining;
- A description of the effects of the facility on archaeological and historic resources;
- A description of the effects of the facility on the natural environment, including effects on air and water quality resources and flora and fauna;
- A description of the effects of the facility on rare and unique natural resources;
- Identification of human and natural environmental effects that cannot be avoided if the facility is approved at a specific site or route; and
- A description of measures that might be implemented to mitigate the potential human and environmental impacts and the estimated costs of such mitigative measures.

Review Application

- PUC will notify applicant within 10 days of filing if application is complete
- If rejected, PUC will notify applicant of deficiencies in application
- PUC will not reject applications if missing information can be gathered within 60 days
- The date the chair accepts the application as complete is the first day of the final decision process

B. Environmental Impact Study

The Environmental Quality Board (EQB) shall prepare an environmental impact statement on each proposed large electric power generating plant and high voltage transmission line for which a permit application has been accepted by the chair.

- Scoping process. The EQB shall provide the public with an opportunity to participate in the development of the scope of the environmental impact statement by holding a public meeting and by soliciting public comments.

The EQB shall provide a period of at least seven days from the day of the public meeting for the public to submit comments on the scope of the EIS. The chair shall determine the scope of the environmental impact statement as soon after holding the public meeting as possible.

- Alternative sites or routes. During the scoping process, a person may suggest alternative sites or routes to evaluate in the environmental impact statement. A person desiring that a particular site or route be evaluated shall submit to the EQB, during the scoping process, an explanation of why the site or route should be included in the environmental impact statement and any other supporting information the person wants the chair to consider. The chair shall include the suggested site or route in the scope of the environmental impact statement only if the chair determines that evaluation of the proposed site or route will assist in the board's decision on the permit application.
- Scope of EIS. The scoping process must be used to reduce the scope and bulk of an environmental impact statement by identifying the potentially significant issues and alternatives requiring analysis and establishing the detail into which the issues will be analyzed. The scoping decision by the chair shall at least address the following:
    - the issues to be addressed in the environmental impact statement;
    - the alternative sites and routes to be addressed in the environmental impact statement; and
    - the schedule for completion of the environmental impact statement.
- Matters excluded. When the Public Utilities Commission has issued a Certificate of Need for a large electric power generating plant or high voltage transmission line or placed a high voltage transmission line on the certified HVTL list maintained by the commission, the environmental impact statement shall not address questions of need, including size, type, and timing; questions of alternative system configurations; or questions of voltage.
- Public review. Upon completion of the draft environmental impact statement, the EQB shall make the document available for public review by placing a copy of the document in a public library or other governmental office in each county where the proposed project may be located.
- Informational meeting. The EQB shall schedule an informational meeting to provide an opportunity for the public to comment on the draft environmental impact statement. The meeting must not be held sooner than 20 days after the draft environmental impact statement becomes available. The informational meeting may be held just prior to the holding of a contested case hearing on the permit application. The EQB shall hold the record on the environmental impact statement open for receipt of

written comments for not less than ten days after the close of the informational meeting.

- Final EIS. The EQB shall respond to the timely substantive comments received on the draft environmental impact statement consistent with the scoping decision and prepare the final EIS.

- The EQB shall publish notice of the availability of the final environmental impact statement in the EQB Monitor and shall supply a press release to at least one newspaper of general circulation in the areas where the proposed sites or routes are located.
- Adequacy determination. The board shall determine the adequacy of the final environmental impact statement. The board shall not decide the adequacy for at least ten days after the availability of the final environmental impact statement is announced in the EQB Monitor. The final environmental impact statement is adequate if it:
  - addresses the issues and alternatives raised in scoping to a reasonable extent considering the availability of information and the time limitations for considering the permit application; and
  - provides responses to the timely substantive comments received during the draft environmental impact statement review process.
- If the board finds that the environmental impact statement is not adequate, the board shall direct the staff to respond to the deficiencies and resubmit the revised environmental impact statement to the board as soon as possible.
- The applicant for a site permit or route permit shall pay the reasonable costs of preparing and distributing an environmental impact statement.

Contested Case Hearing

1. Hearing. The EQB shall hold a contested case hearing after the draft environmental impact statement is prepared on all applications for a site permit or a route permit. The hearing must be conducted by an administrative law judge from the Office of Administrative Hearings. At least a portion of the hearing must be held in a county where the proposed large electric power generating plant or high voltage transmission line would be located.
2. Issues. Once the Public Utilities Commission has determined: questions of need, including size, type, and timing; questions of system configuration; and questions of voltage; those issues must not be addressed in the contested case hearing.
3. Joint hearing. If the board determines that a joint hearing with the Public Utilities Commission to consider both permitting and need issues is feasible, more efficient, and may further the public interest, the board may decide to hold a joint hearing with the approval of the commission. The board may also elect to hold a joint hearing with other states pursuant to Minnesota Statutes.

Final Decision

1. Timing. The board shall make a final decision on a site permit or a route permit application within 60 days after receipt of the report of the administrative law judge. A final decision must be made within one year after the chair's determination that an application is complete. The board may extend this time limit for up to three months for just cause or upon agreement of the applicant.
2. EIS adequacy. The board shall not make a final decision on a permit until the board has found the environmental impact statement to be adequate.
3. Certificate of need decision. The EQB shall not make a final decision on a permit for a project that requires a Certificate of Need from the Public Utilities Commission until the applicant has obtained the necessary approval from the Public Utilities Commission.
4. Notice. The EQB shall publish notice of its final permit decision in the State Register within 30 days of the date the board makes the decision. The EQB shall also publish notice in the EQB Monitor. The EQB shall mail notice of its final permit decision to those persons whose names are on the project contact list. The EQB shall post notice of the final decision on the agency's Web page, if possible.

Alternative Siting Process:

- high voltage transmission lines of between 100 and 200 kilovolts;
- high voltage transmission lines in excess of 200 kilovolts and less than five miles in length in Minnesota;
- high voltage transmission lines in excess of 200 kilovolts if at least 80 percent of the distance of the line in Minnesota will be located along existing high voltage transmission line right-of-way;
- a high voltage transmission line service extension between 200 and 300 kilovolts to a single customer and less than ten miles in length;
- a high voltage transmission line rerouting to serve the demand of a single customer when the rerouted line will be located at least 80 percent on property owned or controlled by the customer or the owner of the transmission line.

1. Application. The applicant for a site or route permit for any of the projects listed in subdivision 2 who chooses to follow these procedures shall submit information as the board may require, but the applicant shall not be required to propose a second site or route for the project. The applicant shall identify in the application any other sites or routes that were rejected by the applicant and the board may identify additional sites or routes to consider during the processing of the application. The chair of the board shall determine whether an application is complete and advise the applicant of any deficiencies.

2. Environmental review. For the projects identified in subdivision 2 and following these procedures, the board shall prepare an environmental assessment. The environmental assessment shall contain information on the human and environmental impacts of the proposed project and other sites or routes identified by the board and shall address mitigating measures for all of the sites or routes considered. The environmental assessment shall be the only state environmental review document required to be prepared on the project.

3. Public hearing. The board shall hold a public hearing in the area where the facility is proposed to be located. The board shall provide opportunity at the public hearing for any person to present comments and to ask questions of the applicant and board staff. The board shall also afford interested persons an opportunity to submit written comments into the record.

4. Timing. The board shall make a final decision on an application within 60 days after completion of the public hearing. A final decision on the request for a site permit or route permit under this section shall be made within six months after the chair's determination that an application is complete. The board may extend this time limit for up to three months for just cause or upon agreement of the applicant.

Final Decision

- No site permit shall be issued in violation of the site selection standards and criteria established in this section and in rules adopted by the board. When the board designates a site, it shall issue a site permit to the applicant with any appropriate conditions. The board shall publish a notice of its decision in the State Register within 30 days of issuance of the site permit.

- No route designation shall be made in violation of the route selection standards and criteria established in this section and in rules adopted by the board. When the board designates a route, it shall issue a permit for the construction of a high voltage transmission line specifying the design, routing, right-of-way preparation, and facility construction it deems necessary and with any other appropriate conditions. The board shall publish a notice of its decision in the State Register within 30 days of issuance of the permit.

Appendix 3
Estimated Major-Project Schedule from Pre-certification Activities to In-Service Date

Access Project -- Schedule Milestones
June 2006 – June 2013

June 2006 – Nov. 2008

Route Selection and CPCN Submssion:
- Initiate project team and project budget
- Establish project study area and maps
- Identify impacted stakeholders and engage public outreach
- Preliminary routing and corridor analysis
- Hold first round open houses to gain public input
- Environmental field work for and development of initial route alternatives
- Hold second round of open houses
- Refine routes based on input and further environmental analysis
- Hold third round of open houses
- Define final proposed and alternate routes for CPCN
- Hold pre-CPCN open house to present final routes
- File CPCN by November 2008

Nov. 2008 – Jan. 2010

PSCW Review Process:
- CPCN Completeness Determination
- EIS Scoping Process
- PSCW Hearing
- CPCN Order issued

Jan. 2010 – April 2012

PSCW Review Process:
- Permitting
- Surveying
- Detailed Design
- Land Acquisition
- Materials Procurement

Nov. 2010 – June 2013

Project Construction:
- ROW Clearing
- Line Construction

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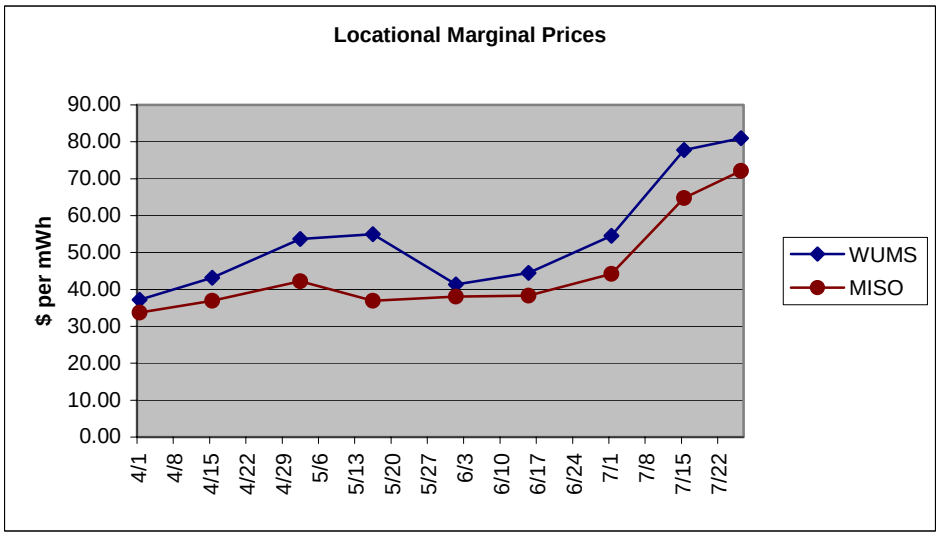
Appendix 4
WUMS/MISO LMPs and Dollar Impacts

WUMS-Midwest ISO (MISO) LMP Comparison for Selected Days

Day-ahead Locational Marginal Prices
($ per mWh)

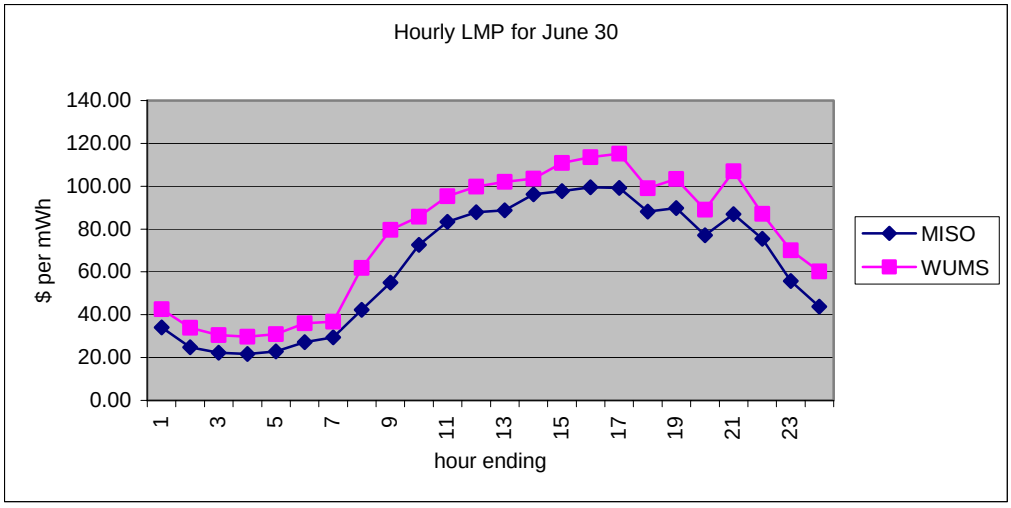
Date	7/26	7/15	7/1	6/15	6/1	5/16	5/2	4/15
Day of the Week	Tues	Fri	Fri	Wed	Wed	Mon	Mon	Fri
WUMS	80.97	77.75	54.53	44.48	41.36	54.99	53.65	43.20
CINERGY.HUB	78.62	54.52	42.88	37.68	36.86	35.87	40.20	37.78
ILLINOIS.HUB	70.79	55.58	44.00	37.33	36.23	35.40	41.19	37.36
MICHIGAN.HUB	75.80	73.95	48.98	40.03	39.00	37.41	42.90	39.33
MINN.HUB	60.12	84.67	31.93	34.18	37.56	33.76	41.99	32.59
MISO	72.14	64.81	44.23	38.32	38.06	36.92	42.22	36.95
WUMS/MISO LMP Differential	8.83	12.94	10.30	6.16	3.30	18.07	11.43	6.25



The MISO Day-ahead LMP data consisted of hourly LMP data for load zones, generator nodes, interfaces, and hubs. Selected days for the months the energy market was operating were selected. The days were at the beginning and the middle of each month, and each day was a weekday. The WUMS LMP calculation is an unweighted average of the day-ahead LMPs of the load zones (*i.e.*, Wisconsin Electric, Madison Gas & Electric, Wisconsin Public Service, Alliant East, and UPPCo) that make up the ATC footprint.

Dollar Impact of WUMS-MISO LMP Differential using a Daily Load Shape (June 30, 2005)

Hour Ending	Day-ahead LMP for June 30 MISO ($ per mWh)	WUMS ($ per mWh)	LMP Difference ($ per mWh)	WUMS Load for June 30 (mW)	Dollar Impact of LMP Difference
1	34.14	42.59	8.45	8023	$67,774
2	24.83	33.94	9.11	7658	$69,738
3	22.20	30.47	8.27	7467	$61,729
4	21.67	29.72	8.05	7287	$58,687
5	22.88	30.86	7.98	7365	$58,799
6	27.17	36.05	8.88	7761	$68,884
7	29.43	36.81	7.38	8488	$62,660
8	42.26	61.92	19.66	9260	$182,035
9	55.05	79.64	24.59	9809	$241,153
10	72.66	85.83	13.17	10093	$132,926
11	83.31	95.26	11.95	10341	$123,608
12	87.83	99.86	12.03	10593	$127,429
13	88.80	101.98	13.18	10716	$141,276
14	96.19	103.51	7.32	10927	$79,961
15	97.65	110.83	13.18	10890	$143,546
16	99.50	113.60	14.10	11030	$155,527
17	99.14	115.17	16.03	11051	$177,192
18	88.19	99.01	10.82	10923	$118,151
19	89.85	103.32	13.47	10621	$143,105
20	77.10	89.08	11.98	10203	$122,261
21	86.90	106.92	20.02	9875	$197,712
22	75.39	87.15	11.76	9707	$114,122
23	55.80	70.11	14.31	8933	$127,819
24	43.84	60.17	16.33	8140	$132,904
Total					**$2,908,996**



Appendix 5

RISK and TECHNOLOGY of ELECTRICITY SUPPLY, EMPIRICAL EVIDENCE of PRICE VARIATION OVER TIME and SPACE, DELMARVA CASE STUDY, EMPIRICAL EVIDENCE of PRICE VOLATILITY

Prepared by Christensen Associates Energy Consulting LLC

Risk – electricity price risk – is costly to participants in wholesale markets, and to retail service providers in particular. Electricity price risks are determined by a broad range of possible events in the future. These events include both market and physical phenomena which, should they occur, result in sharply higher prices that can impose economic harm on retail consumers and the State of Wisconsin as a whole. History suggests that the most relevant of potential events include unusually high costs of primary fuels, abnormal weather patterns, unexpected outages of generators, unexpected closure of generation stations, and outages of key transmission facilities.

Economic risks attending electricity are evidenced by occasional large-scale power outages such as the August 14, 2003 event within the Eastern Interconnection, and by the substantial volatility in power prices over time and across locations and areas. Arguably, electricity prices contain more inherent short-term price risk than that observed in *any* of numerous other commodity markets.

The risks attending power markets are determined by the technology and physical nature of power supply.[1] It is the tightly integrated and inseparable nature of electricity supply

[1] Power systems consist of electricity circuits including power generation (supply) and power consumption and use (demand). Power circuits include transmission meshed networks and distribution circuits, including primary and secondary radial and loop systems. To a lesser extent, transmission facilities also consist of radial circuits. Also, through interties to other distribution circuits, distribution facilities can assume a meshed configuration.

Power systems are managed according to formal procedures of control in both real time (operating) and forward periods. Power flows within networks behave according to physical laws. In the case of meshed network transmission, power flows are characterized by parallel path flows. This means that power travels along multiple lines from locations where it is produced (network source locations) to locations where it is consumed and used (network sink locations).

Power flows and system operating conditions are necessarily maintained within strict limits. Power flow limits are often described as thermal limits, stated in megawatts or megavolt amperes. Limits of acceptable operating conditions are also defined in terms of voltage, stated in per unit terms of roughly 5% variation from unity, and system stability where limits are often defined as thermal limits. Also, power systems are on occasion operated under the emergency conditions, where thermal, voltage, and stability limits are restated to account for the possibility of contingency events.

technologies that sets electricity apart from other commodities, and three characteristics are worthy of mention. First, electricity cannot be readily stored, and thus inventories are unavailable to hedge risks. Second, power systems must ensure that the level of supply is equivalent to the level of demand over the course of small time steps. Third, power systems are laced with strong network externalities.[2] In short, the physics of power systems imply:

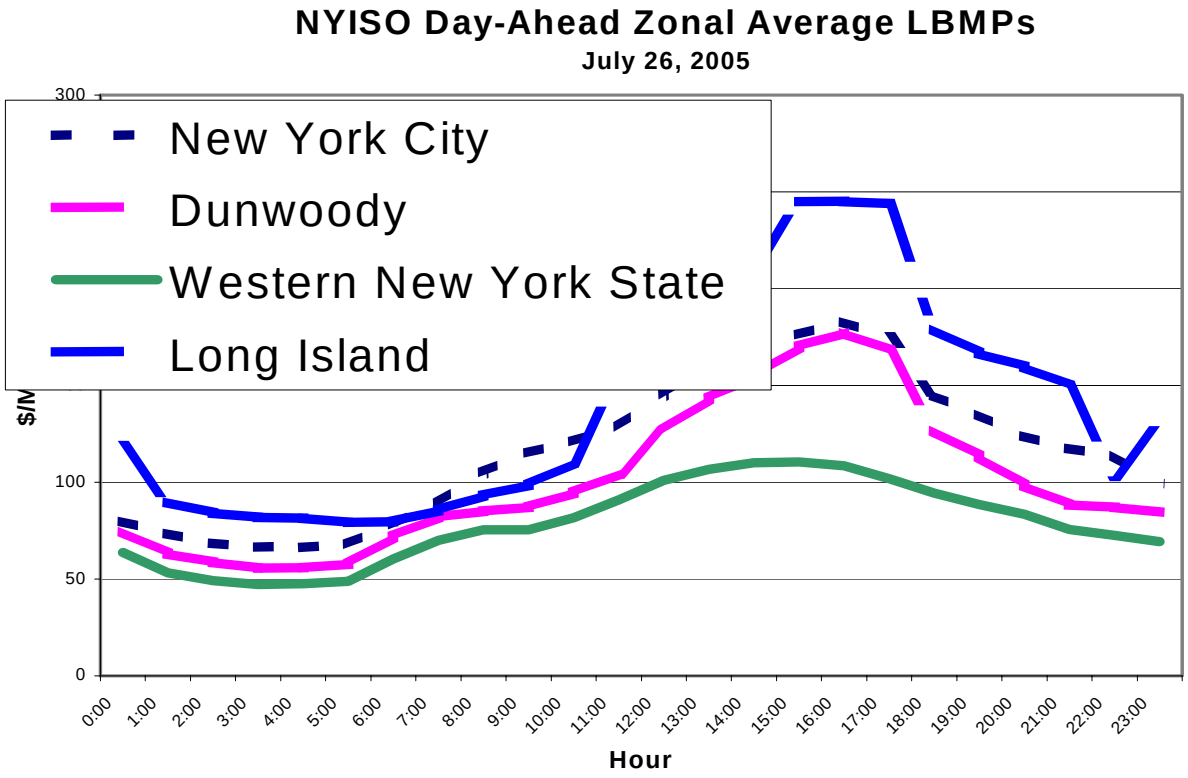
- economic costs and market prices are highly specific to time and location;
- electricity prices can reveal exceptionally high short-term price volatility, suggesting that market participants are exposed to costly and harmful price risk. As a consequence, vehicles to hedge price risks, such as plentiful supply of transmission capability, are desirable;
- locational price differences are largely – though not exclusively – a consequence of congestion and line losses of transmission. It is transmission and only transmission that gives rise to the locational basis of prices within unbundled wholesale markets;[3]
- price and congestion risks are not normally distributed. Rather, price risks in the case of electricity markets are highly skewed. Hourly prices can vary by a factor of 30-to-1 over the course of a fairly high-cost day, though the hourly prices of a typical day may vary by a factor of only 3-to-1.

Real world empirical evidence is readily at hand, and variation in prices by time and location can be easily demonstrated. Shown below in Figure 1 are hourly prices for a recent day for selected zones of the New York Independent System Operator's market territory.

[2] The attribute of network externalities means that events such as change in the level of load, level of supply, or in the availability of facilities (generators, transformers, lines) at a specific location have implications for the economic cost and prices experienced at many locations of a regional market.

[3] It is useful to mention that, in the future, the prices of reserve services within unbundled wholesale markets may also be differentiated by area and, potentially, by nodal locations.

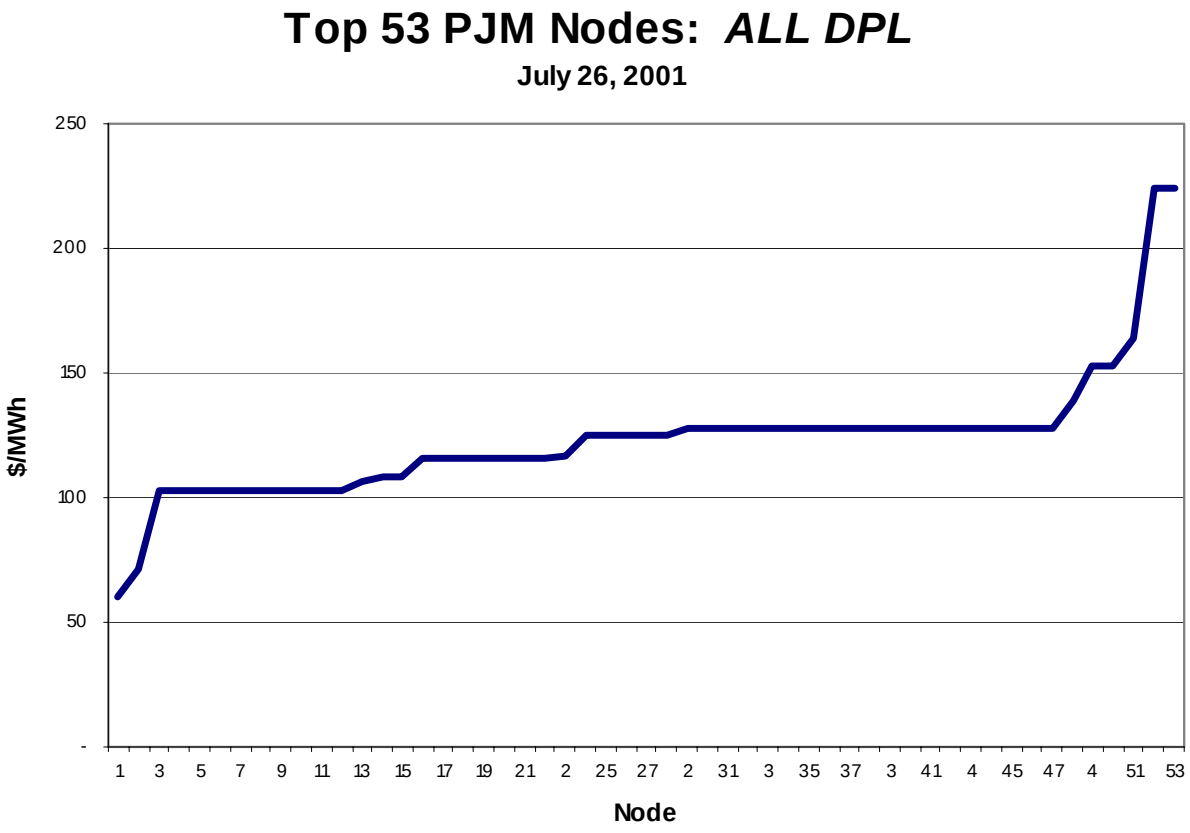
Figure 1



Substantial differences in prices over time and zones are observed. And while the loads of July 26 2005 were fairly high, the New York market was characterized by adequate supply on this date. Yet, prices still varied from a low of $70 per MWh on average across all zones to a high of about $245 per MWh being reached during the late afternoon hours, in the case of Long Island. Also, while the price differences between the Eastern zones and the Western zones were relatively modest during the off-peak hours, the zonal price differences between East and West reached a difference of twofold by late afternoon. Price differences over time are due predominantly to the characteristic of non-storability; price differences across the zones are attributable to transmission congestion and line losses.

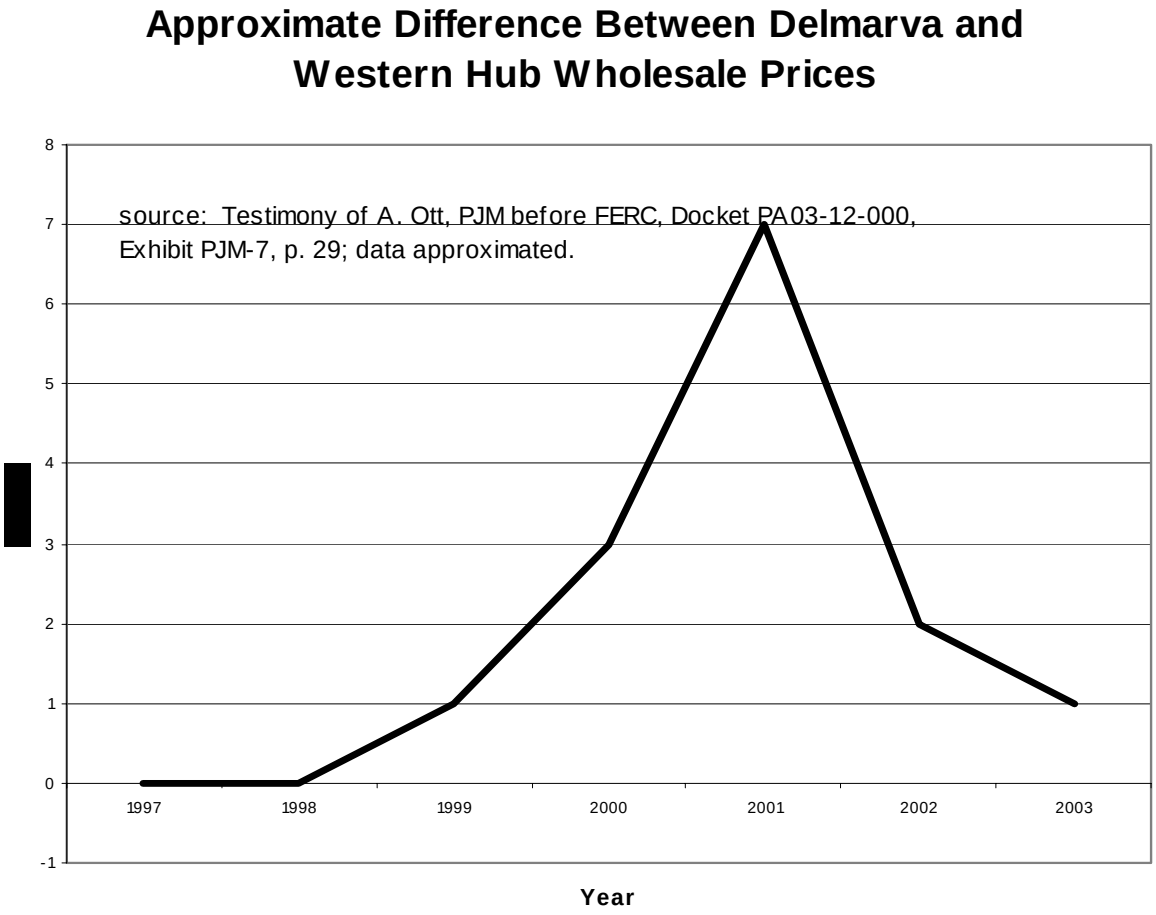
Useful lessons about how improved transfer capability can relieve the costly effects of congestion can be gleaned from a case example, which also takes place in the restructured wholesale markets of the Eastern U.S. The specific case is Delmarva Power and Light (DPL), a major service provider within the PJM market. The Delmarva Peninsula faced chronic congestion and high power supply costs at the outset of the PJM market. To illustrate, Figure 2 below presents sample data from 2001, also for the day of July 26. As observed, the 50+ highest-priced locations of the entire PJM market, on this date, were all situated within DPL's service territory.

Figure 2



Recently, Delmarva's costly power supply condition has been partially relieved, however, as a consequence of the implementation of expanded capability to transport comparatively low-cost power into the Peninsula. As demonstrated by Figure 3 below, the expanded transfer capability has had a mitigating impact on the zonal prices within the Delmarva Pennsylvania vis-à-vis PJM West.

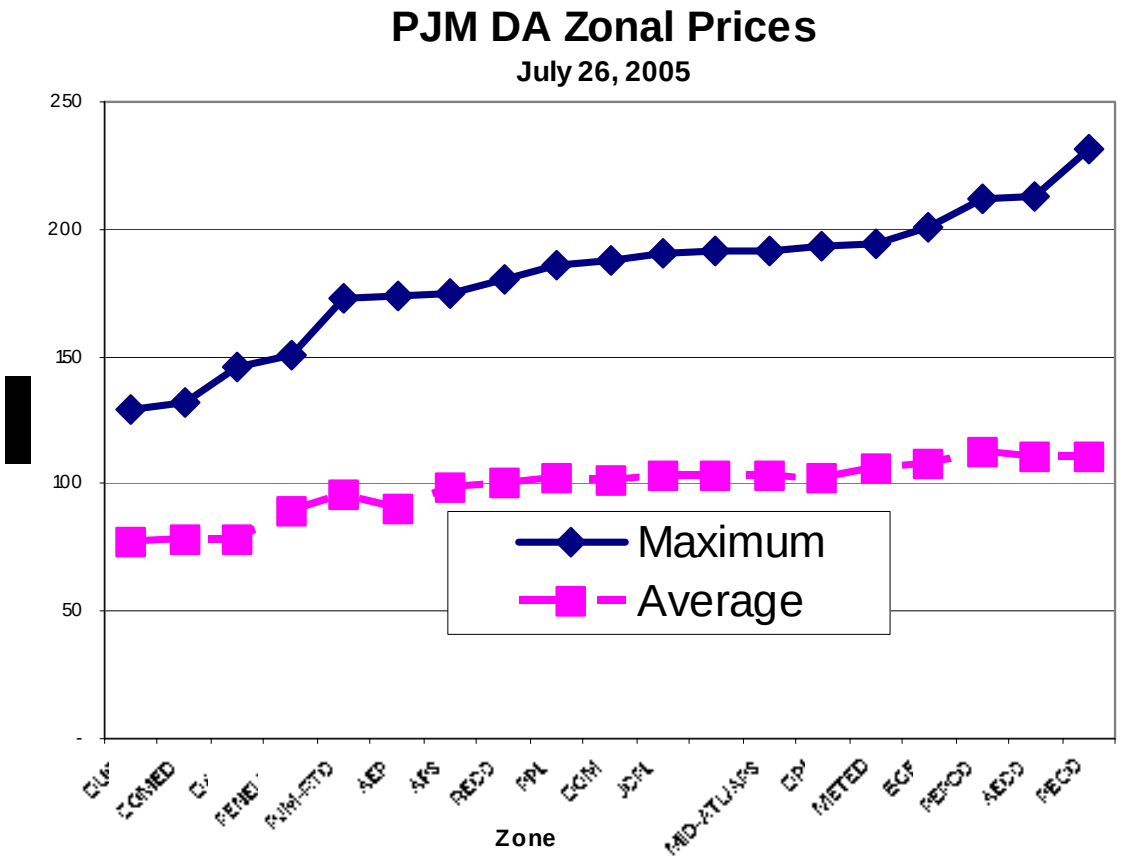
Figure 3



Here, the relatively high zonal price differences of 2001 have been largely mitigated through expanded capability (testimony and exhibits of Andrew Ott, as filed before the FERC).

The result of increased capability to Delmarva is also demonstrated in Figure 4, below. Here, the average and maximum hourly zonal prices for the zones of PJM, also for July 26, 2005, are ordered from lowest to highest. As in the case of New York, PJM zones when ordered from the lowest to the highest prices result in the grouping of the zones of the West region and the zones of the East region of PJM. The Eastern zones include DPL, Metropolitan Edison, Baltimore Gas and Electric, Potomac Electric Power Company, Atlantic City Electric and, located to the far right, the Philadelphia Electric Company (PECO) zone with the highest prices. DPL remains a high-cost zone currently, as it is in the East; nonetheless, DPL's position as the highest cost zone, at least for this day, has been surrendered to PECO. As expected, increases in the average zonal prices are associated with greater variation in hourly prices. That is, across the zones, the difference between the maximum hourly price and the average hourly price increases, as the average zonal price rises.

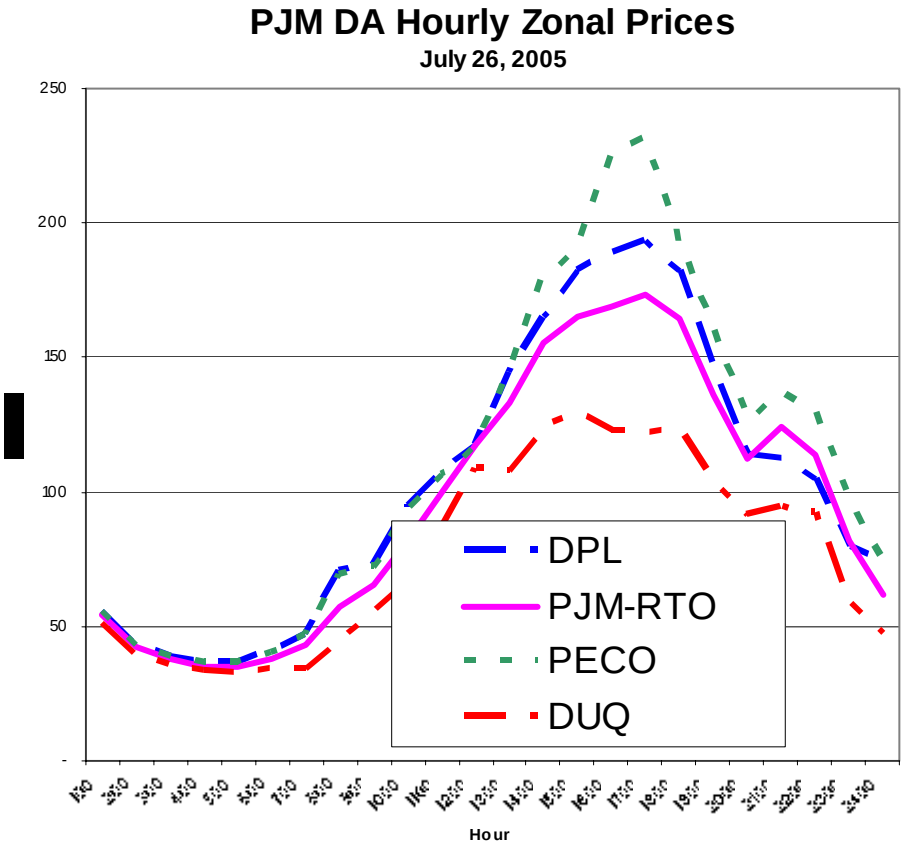
Figure 4



In order to demonstrate how prices vary by timeframe, Figure 5 below presents hourly zonal prices for selected zones of PJM and for PJM overall, also for July 26 2005. Three observations are gleaned from these data. First, the prices in East PJM (PECO, DPL) are higher than prices in the West (Duquesne Light Company, or DUQ). Second, the prices are virtually identical across all zones during off-peak hours, as transmission networks were (virtually) unconstrained on this date. Third, as loads rise over the course of the day, low cost generation resources of the West are used to satisfy loads in the East. The result is an increase in the number (and/or level) of congested flowgates as flows are from West to East. In turn, zonal price differences rise.[4] As observed, the off-peak to peak period zonal price differences range from 6-to-1 for PECO, which resides in the East, to 3-to-1 for Duquesne Light Company in the West.

[4] These summary level data do not provide a basis to say how the congestion constraints are managed. As a matter of principle, the number of generators involved in redispatch is equal to 1 plus the number of constrained flowgates. However, locational price differences due to congestion are specific to a number of factors, and are directly related to the generators involved in redispatch. The relevant factors include the power transfer distribution factors of generators with respect to the congested flowgates (which is related to location of the generators with respect to the flowgates), and the running cost differences of generators.

Figure 5



The following diagrams, Figures 6 – 9, present day-ahead forward prices for several hubs and areas within the Eastern Interconnection. It is readily apparent that, as described earlier, electricity markets are characterized by unusually high price volatility.

Figure 6

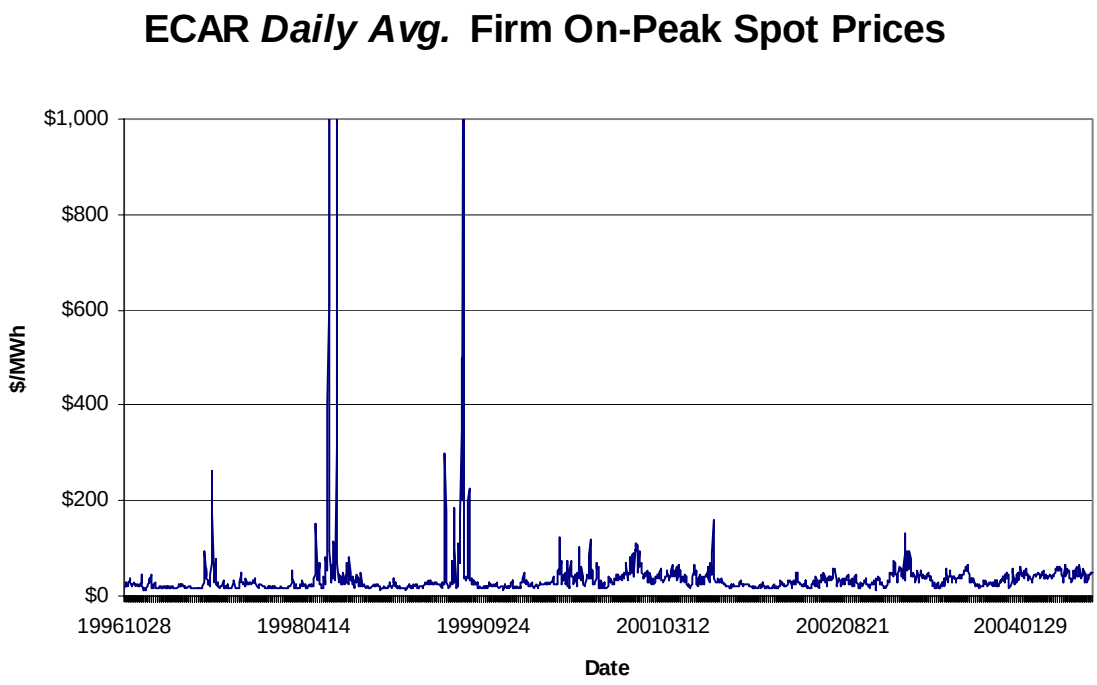


Figure 7

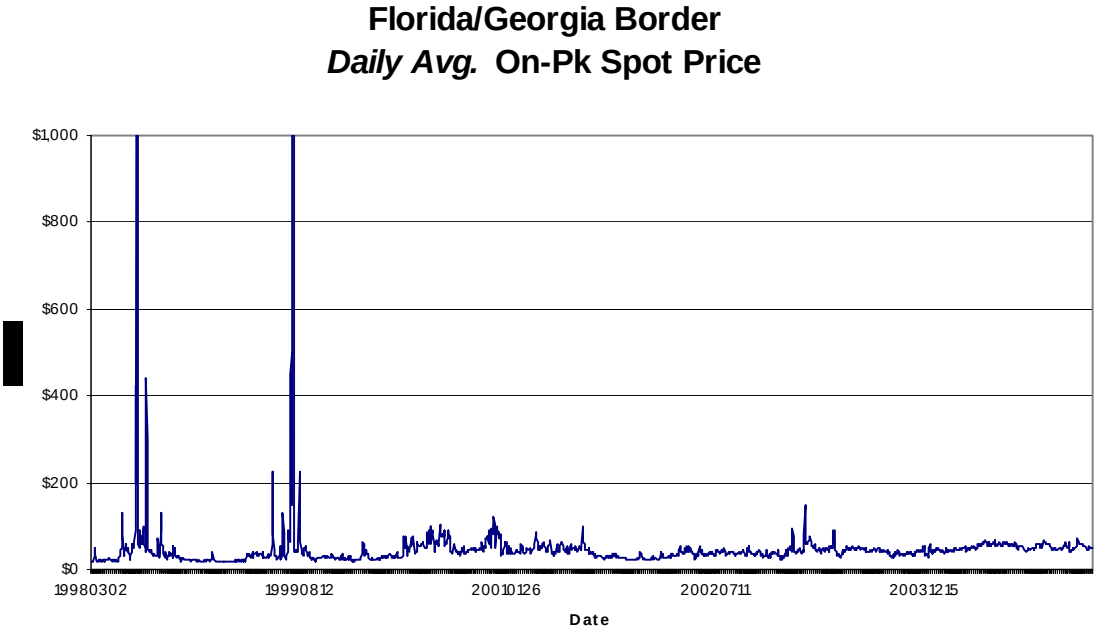


Figure 8

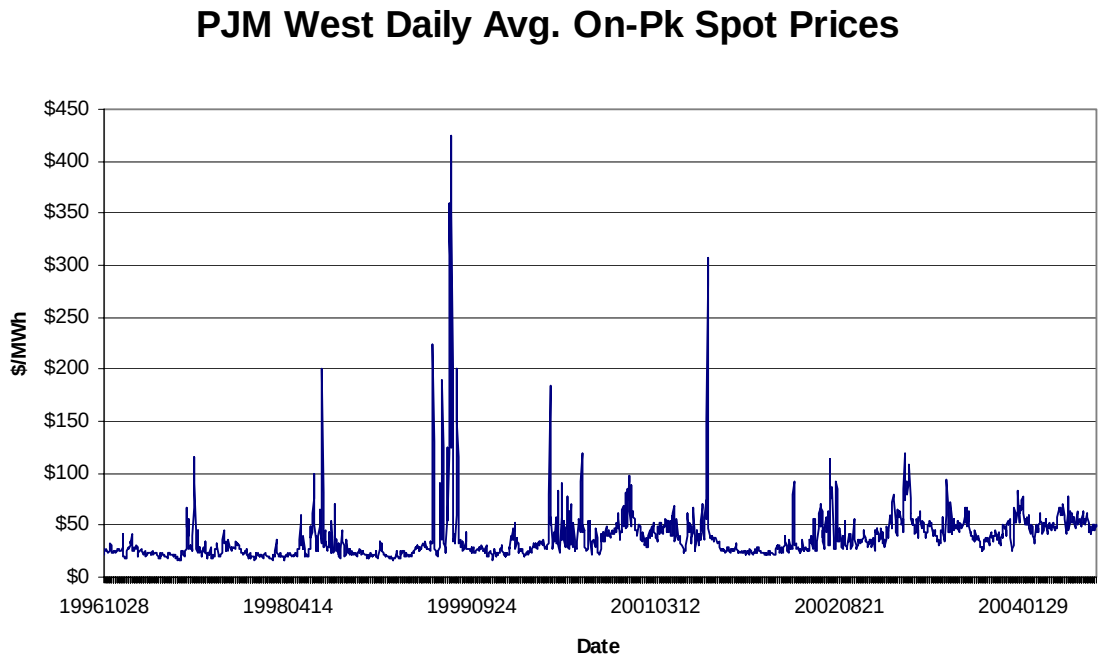
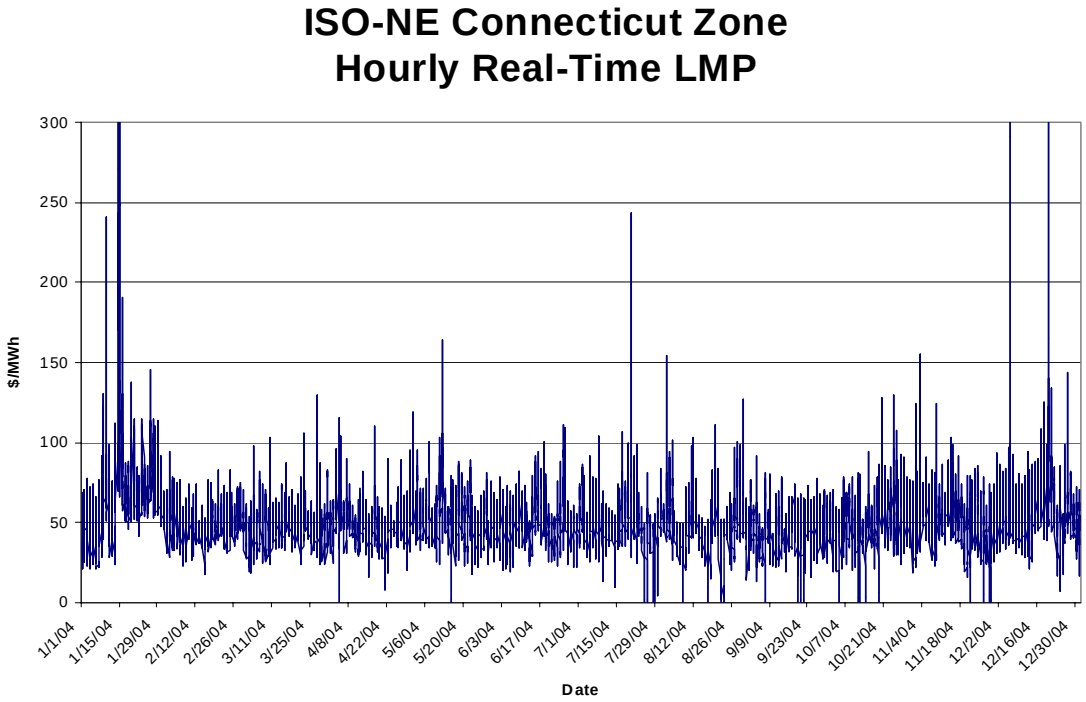


Figure 9



Appendix 6

Glossary of Terms

ACCCC	AC Contingency Checking
ALJ	Administrative Law Judge
ALT-W	Alliant Energy West
ASD	Average Standard Deviation
ASI	Access Study Initiative
ATC	American Transmission Company
CPCN	Certificate of Public Convenience and Necessity
CNF	Capacity Needs Forum
CT	Combustion Turbine
DPC	Dairyland Power Cooperative
DPL	Delmarva Power & Light Company
DNR	Department of Natural Resources
EGEAS	Electric Generation Expansion Analysis System
EHV	Extra High Voltage
EIS	Environmental Impact Statement
EMF	Electro Magnetic Fields
EMT	Energy Markets Tariff
EPRI	Electric Power Research Institute
EQB	Environmental Quality Board
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FTRs	Financial Transmission Rights
GSP	Gross State Product
GWH	gigawatt hours
HVTL	High Voltage Transmission Line
ICC	Illinois Commerce Commission
IMM	Independent Market Monitor
IPP	Independent Power Producer
ISMNEX	Iowa Southern Minnesota Exploratory Study
KV	kilovolt
LMP	Locational Marginal Price
LODF	Line Outage Distribution Factors
LOLE	Loss of Load Expectation
LRS	Load Ratio Share
LSE	Load Serving Entity
MAIN	Mid-American Interconnected Network
MAPP	Mid-continent Area Power Pool
MCA	Multi-Criteria Analysis
MGE	Madison Gas and Electric Company
MISO	Midwest ISO
MMWG	Multi-regional Modeling Work Group
MPSC	Michigan Public Service Commission
MTEP	Midwest Transmission Expansion Plan
MUIST	Maximum Utilization of System Transfers
MW	megawatt

MWSI	Minnesota-Wisconsin Stability Interface
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Council
OASIS	Open Access Same-time Information System
OMM	Optimum Mitigation Measure
OMS	Organization of MISO States
OPF	Optimal Power Flow
PECO	Philadelphia Electric Company
POM	Physical Operation Margin
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PROMOD	Production Model
PSCW	Public Service Commission of Wisconsin
PTF	Power The Future
PUC	Public Utility Commission
RECB	Regional Expansion Criteria and Benefits
REMI	Regional Economic Models Inc.
RPS	Renewable Portfolio Standards
RPU	Rochester Public Utilities
RR	Renewable Resources
RTO	Regional Transmission Organization
ROW	Right of Way
SCED	Security Constrained Economic Dispatch
SEA	Strategic Energy Assessment
TLR	Transmission Loading Relief
TO	Transmission Owner
TRELSS	Transmission Reliability Evaluation Large Scale Systems
TTC	Total Transfer Capability
TYA	Ten Year Assessment
UPPCO	Upper Peninsula Power Company
VSAT	Voltage Security Assessment Tool
WEP	Wisconsin Electric Power Company
WIRES	Wisconsin Interface Reliability Enhancement Study
WPL	Wisconsin Power and Light Company
WPPI	Wisconsin Public Power Inc.
WPS	Wisconsin Public Service Corporation
WRAO	Wisconsin Reliability Assessment Organization
WUMS	Wisconsin Upper Michigan Systems