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MTEP07

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Growing the Grid

The Midwest ISO Transmission Expansion Plan

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Section 1.0 Executive Summary

1.1 Introduction and Highlights

This Midwest ISO Transmission Expansion Plan 2007 (MTEP 07) is the fourth regional expansion plan issued by the Midwest ISO. MTEP 07 builds on the grid improvements identified in MTEP 06 that was approved by the Midwest ISO Board of Directors in February 2007. Twenty-eight (28) new projects are being recommended for inclusion in the regional plan at this time, based on analyses that were completed as a part of MTEP 07. These incremental upgrades will ensure the continuing reliable operation of the Midwest ISO grid and provide for additional new generation interconnection to the Midwest ISO system.

Combined with the expansions identified in MTEP 06, the plan includes $2.2 billion in approved projects through the year 2013, and over $800 million of investment placed into service in 2006 and 2007. In addition to addressing load growth and new generation driven reliability needs, the approved projects identified in the plan will reduce the loadings on a majority of the constrained facilities that define the three Narrow Constrained Areas identified within the market footprint.

A two pronged evaluation was performed in MTEP 07 to provide for updated reliability needs: A complete screen of NERC reliability contingency criteria applied to new system models of the 2013 and the 2018 Midwest ISO projected systems, and ; 2) an evaluation of previously identified Proposed Projects from Appendix B to the MTEP 06 report to see which projects need to be committed for implementation. The results of these analyses have provided an assessment of the 2013 and 2018 reliability performance of the system, identification of new Proposed Projects to meet newly identified needs in the expanded planning horizon, and identification of projects that are now recommended to be committed for implementation. Each of these results is detailed in this report.

Reliability Analyses Summary

Twenty eight (28) new projects are recommended for implementation in this MTEP 07. These 28 projects include 13 Baseline Reliability Projects that are needed to keep pace with native and network customer load growth, 5 projects classified as “Other” that are driven by local area reliability or economic criteria, 9 new Generation Interconnection Projects, and 1 Transmission Delivery Service Project. The generation related transmission upgrades will enable the reliable interconnection of 1900 MW of additional generating capacity to the Midwest ISO grid. The 28 new transmission projects add to the 210 Appendix A projects already approved in prior MTEP, help to ensure a reliable transmission system through the 2013 planning horizon.

The MTEP 07 effort provided a comprehensive testing of the reliability performance of the Midwest ISO grid against the NERC Planning Standards. In total, 79,000 separate contingency conditions were evaluated for the 2013 timeframe, involving 11,000 single facility outages, and 68,000 multiple facility outages. Both steady state and dynamic system performance was evaluated. These tests revealed that the 373 Planned and Proposed (Appendix A and B) projects are sufficient to resolve nearly all of the contingency conditions evaluated. A relatively small number (6) of single contingent events across the system have the potential to result in overloads or low voltage conditions if not resolved by 2013. The Midwest ISO planning staff is working with the Transmission Owners in the affected systems to identify the appropriate solutions to these issues, and will report on these in the next MTEP report. Similarly, some multiple contingency events are also expected to result in design criteria violations. For these types of events it may be possible to develop operating steps such as redispatch options, switching procedures, or if necessary load shedding options, to ensure system reliability. The staff is also working with the affected Transmission Owners to develop either Network Upgrades, or an appropriate operating step before the condition develops. As always, the Midwest ISO will continue to monitor these unresolved issues in both seasonal operating studies and in future MTEP tests and to develop solutions before the load condition are such that the event creates a system problem.

In accordance with NERC Standards, reliability analyses was extended through the 10 year planning horizon to test those marginal conditions from the 2013 analyses that could require longer lead time solutions. Contingencies resulting in loading within 10% of design in 2013 were further tested for in 2018. This analysis demonstrated that there were bulk power transformers at three substations that had Category B contingent loadings in the range of 90 to 100% in the 2013 summer peak case which load to over 100% but less than 110% in 2018 summer peak case. This level of projected loading by 2018 is not of concern, as these transformer loading issues can be resolved with modest upgrades within a few years prior to the overloading condition.

Committing Previously Proposed Projects

In order to determine which Proposed Projects in Appendix B need to be committed for implementation in order to ensure reliability, Midwest ISO staff reviewed system conditions for which the projects provide a solution, and compared the expected need date of the condition to the estimated lead-time of the project. A preliminary list of projects was prepared by Midwest ISO staff and reviewed with Transmission Owners to confirm that our estimates were appropriate in light of any additional information they may have on project drivers and leads times.

After finalizing the list, the 13 Baseline Reliability Projects were recommended for movement to Appendix A to be competed by the Transmission Owners. Detailed project reviews and justifications were prepared by Midwest ISO staff for project eligible for regional cost sharing under Attachment FF of Midwest ISO Energy Markets Tariff (EMT). The project justifications were reviewed at Planning Subcommittee meetings. Cost allocations were determined for eligible projects using the MTEP07 Final Plan model for 2013. Cost allocations were presented at the August Planning Subcommittee meeting for review prior to a final open stakeholder cost allocation review meeting with stakeholders that was held on September 7, 2007.

1.2 MTEP 07 Recommended Projects Eligible for Regional Cost Sharing

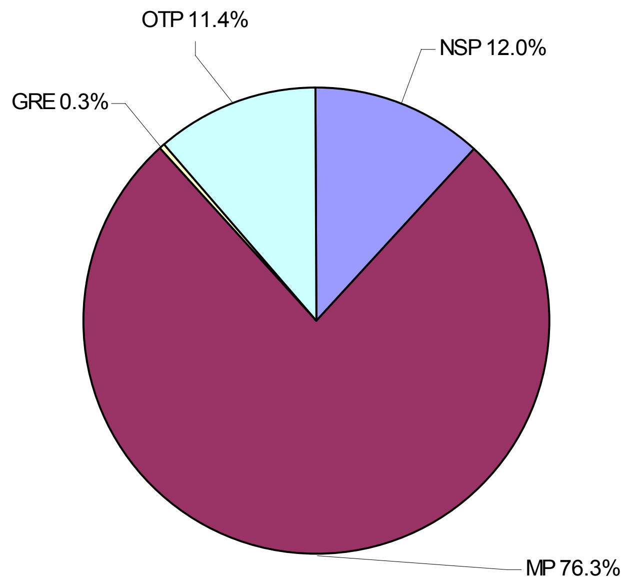
Of the 13 new Baseline Reliability Projects being recommended at this time, 6 of these qualify for regional cost sharing under the RECB I allocation provisions of the tariff. In addition, all generation interconnection Projects are eligible for cost sharing, and 4 of the 9 new Generator Interconnection Projects (GIP) result in cost sharing after the tariff formulae are applied. Each of these cost shared projects are summarized below. The cost of the projects eligible for regional cost sharing is $170.5 million. The portion allocated to others is $82.5 million, including $57.8 million allocated to generation developers. Additional detail on project cost allocation methods and results are provided in Sections 2 and 7 of this report.

1.2.1 Baseline Reliability Projects with Cost Sharing

Each of the following projects that are being recommended and that are eligible for cost sharing under the RECB I provisions of the tariff is described in more detail in Chapter 5 of this report. Of the 6 BRP eligible for cost sharing, 2 are in Minnesota, 1 in Illinois, 2 in Indiana, and 1 in Missouri.

Badoura Projects 277 and 1022 (Minnesota)

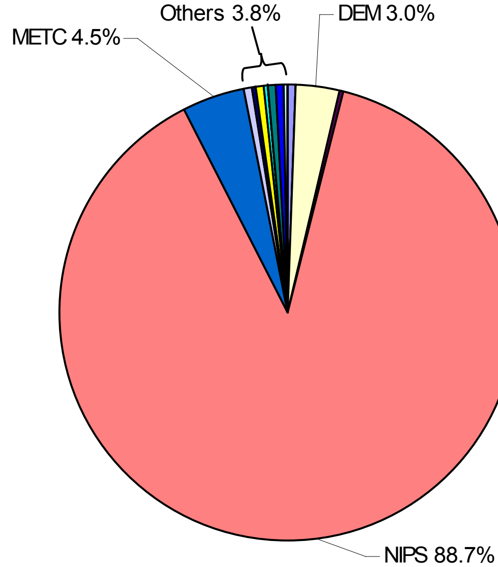
These two projects consist of a group of upgrades being developed by Minnesota Power and Great River Energy with an estimated cost of $37.4 million. A primary driver of these upgrades is to secure the sub-transmission supply network below 115 kV in these areas. The projects result in the development of new 115 kV transmission interconnections between existing 115 kV substations, and as such provide Transmission System grid enhancements, the cost of which will be allocated in accordance with the RECB I provisions of the tariff. Cost shares for this project will be as shown in the pie chart below.



P277,1022 Allocations

Hiple Transformer Project 612 (Indiana)

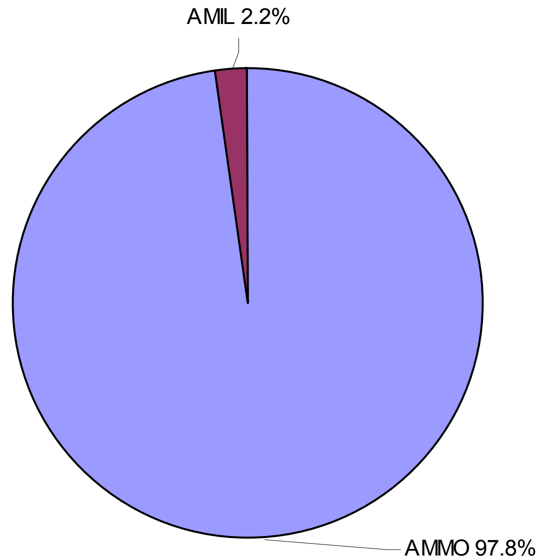
The Hiple transformer project in the NIPSCo system in northern Indiana installs a second 345/138 kV transformer at the existing Hiple substation. This $5.8 million project is needed to resolve a large number of projected overloads under first and second contingency forced outage conditions. The primary alternative of reconductoring the overloaded transmission lines would costs nearly as much as the transformer, and would not resolve the multiple contingency issues, for which over 150 MW of load would have to be shed to resolve the those conditions. Cost sharing for this project is represented below.



P612 Allocations

Big River – Rockwood 138 kV line Project 152 (Missouri)

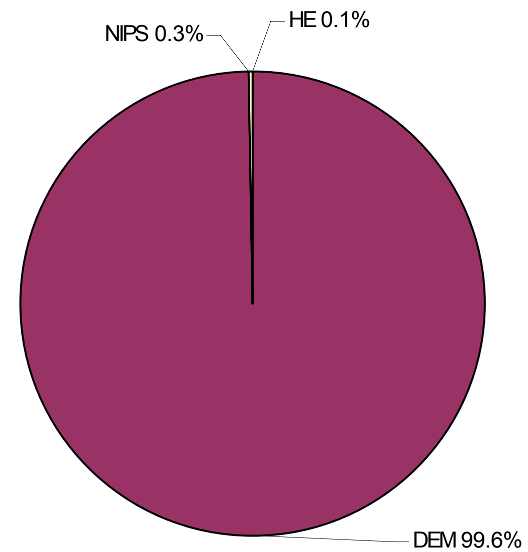
This project constructs a new 10 mile 138 kV line between two existing 138 kV substations, each of which is vulnerable to outages of the radial lines serving them. If the existing supplies to the se two substations were interrupted, 65 MW and 90 MW respectively would be lost at each of the two substations. The new $13.4 million line will reinforce the 138 kV bulk power system in this area. Cost sharing for this project is entirely within the Ameren companies.



P152 Allocations

Crawfordsville-Lafayette SE 138 kV Line Reconductor Project 852 (Indiana)

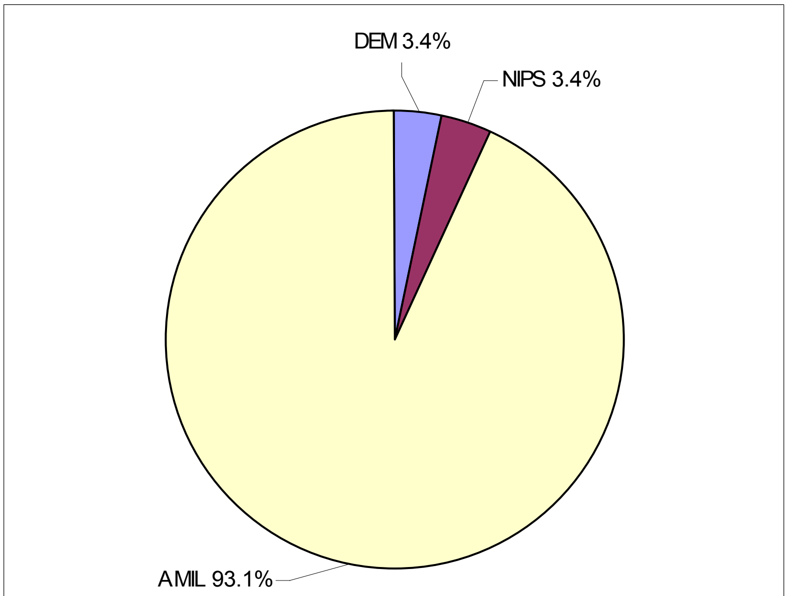
This is an $8.6 million project in the Duke-Cinergy system. The project reconductors 25.4 miles of 138 kV line conductors in order to relieve an overload condition for a single line outage at peak load conditions. This is the lowest cost project that will relieve the overload condition. Cost sharing is very limited for this project due to the minimal change in system configuration that it provides for, as shown below.



P852 Allocations

Sidney-Paxton 138 kV line Project 870 (Illinois)

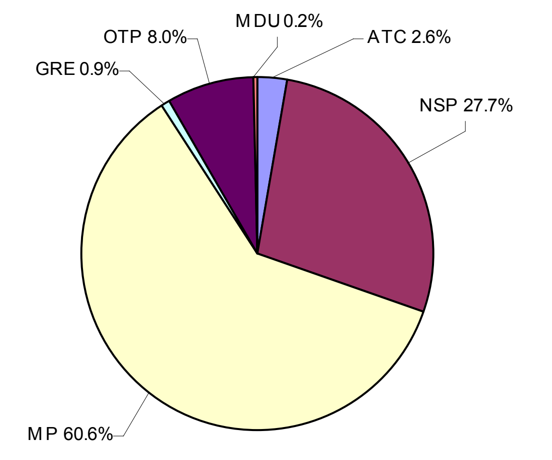
Project 870 is a $5.9 million project on the Ameren IP system to reconductor 18 miles of 138 kV line. The project is needed to relieve a 12 % overload of the line for the outage of a 138 kV line during the longer duration outage of a unit at the Clinton generating station, or if the Clinton generation were not dispatched. Redispatch was ineffective for this condition, and planning for load shed as the alternative option for this condition was rejected as an inferior option as compared to the expansion. Cost allocation is primarily to the constructing zone.



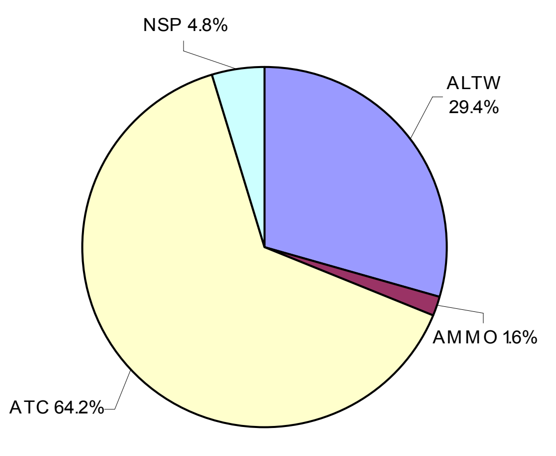
P870 Allocations

1.2.2 Generator Interconnection Projects with Cost Sharing

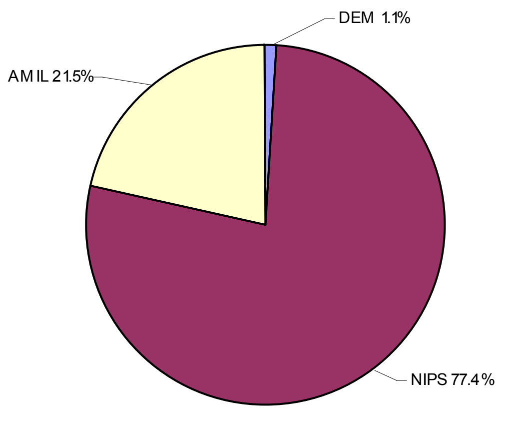
There are 4 Generator Interconnection related transmission expansions that qualify for cost sharing. These four projects add 1400 MW of generation to the grid, and have $97.6 million of associated transmission, of which 50% is assigned to the Interconnection Customers, and 50% is assigned to the transmission customers in various pricing zones according to the RECB formulae. One of the projects is in Minnesota, two are in Indiana, and the other is in Wisconsin. Cost sharing for these transmission projects is shown below.



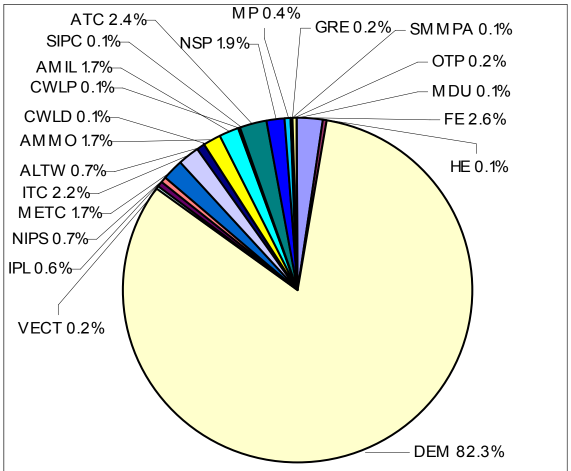
P1025 Pricing Zone Allocations (50%)
G519 Mesaba 600 MW Generator - $38.1M



P1617 Pricing Zone Allocations (50%)
G527 Nelson Dewey 280 MW Generator - $5.51M



P 1615 Pricing Zone Allocations (50%)
G439 Benton County 100 MW Wind - $1.3M



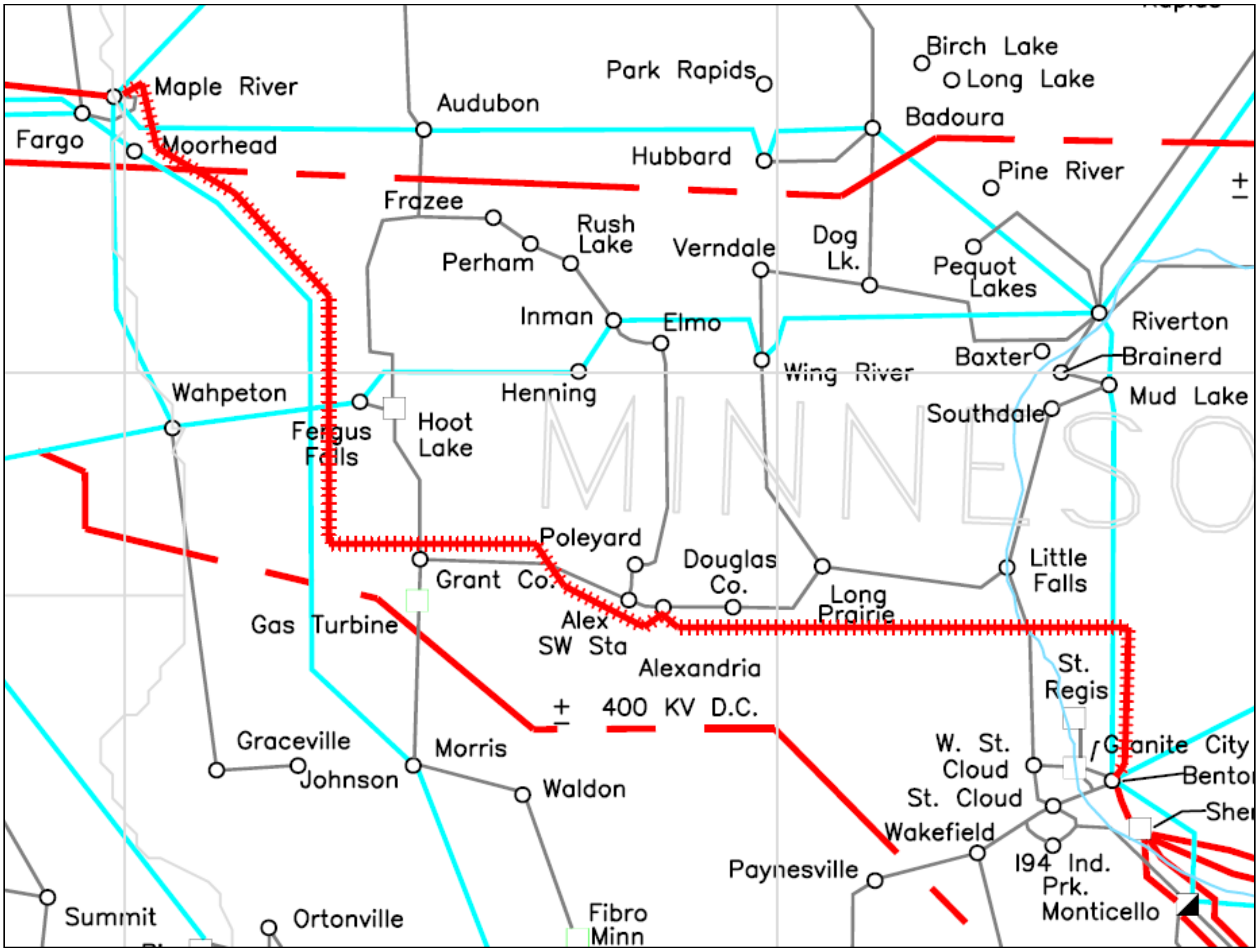
P 1263 Pricing Zone Allocations (50%)
G431 Edwardsport 420 MW Generator - $3.8M

1.2.3 Other Significant Projects Pending Appendix A Recommendation

There are three projects referred to as the CAPX projects that the Midwest ISO is not seeking Board approval for at this time, but for which we expect to do so in the near future. These three projects represent significant bulk power 345 kV expansions of the Midwest ISO transmission system. The three projects add over 500 miles of new 345 kV lines, and several transformer installations to support loads over a wide area of the upper Midwest, and to deliver new renewable generation resources to reliably meet load projections in the region. The three projects are briefly described here and will be further discussed in stakeholder meetings in the next several months as the final cost allocations are determined for these projects.

P286-P287 Fargo-Alexandria-St Cloud-Monticello 345kV line

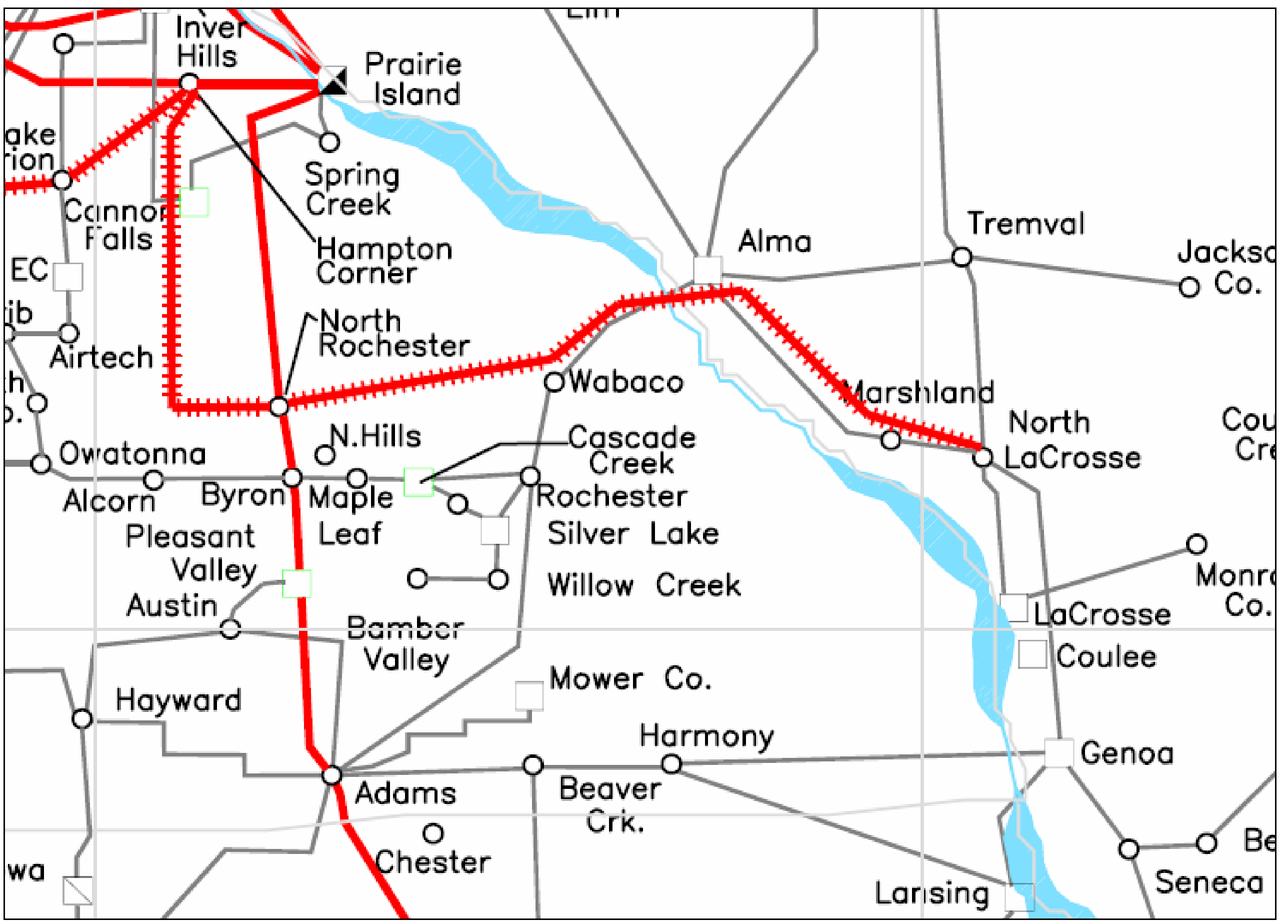
- Estimated Cost: $267.4 million
- Zones/Transmission Owners: GRE, XEL, OTP, MP, MPC, WAPA
- ISD: 2012+
- Project Category: Appendix B currently
  - Pending Cost Allocation Determination
  - Expected to be BRP
- Description:
  - Maple River-Alexandria SS 345 kV line 110.8 miles $117.5M
  - Alexandria SS-Waite Park 345 kV line 64.5 miles $98.4M
  - Waite Park-Monticello 345 kV line 27.9 miles $42.5M
  - Alexandria SS 345/115 kV 448 MVA TX $4.5million
  - Waite Park 345/115 kV 448 MVA TX $4.5



- Justification
  - Resolves NERC Standard issues in three areas along line route
    - Red River Valley at north end
    - Alexandria area to south
    - St. Cloud area near south end
  - Multiple Category B events
  - Multiple Category C events including voltage instability
- Disposition
  - Expect to move to Appendix A as recommended project at a later date
  - Expect to allocate costs under Attachment FF
  - Will hold stakeholder meetings to fully describe justification and cost allocation when proposed cost allocation determined

P1024 – Hampton Corners – Rochester – La Crosse 345 kV line

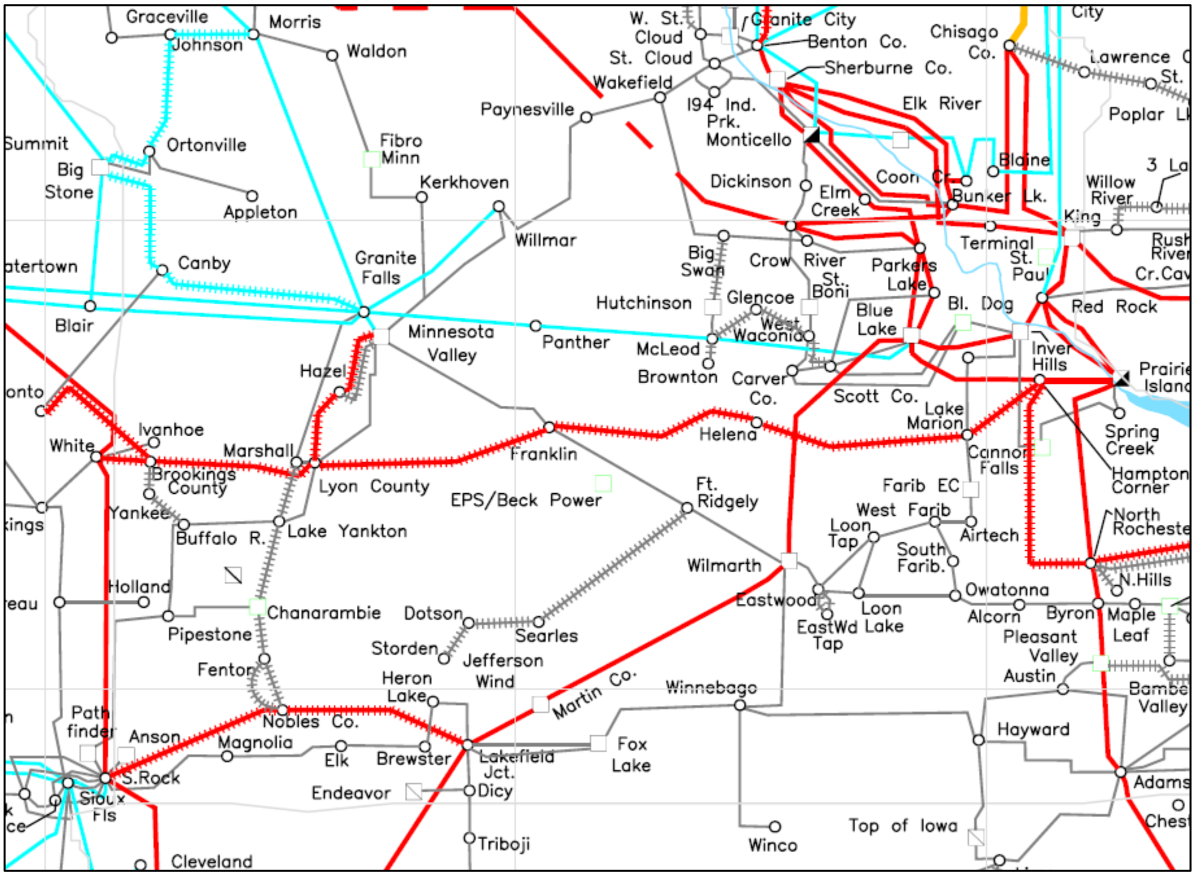
- Estimated Cost: $273 million
- Zone/Transmission Owners: XEL, DPC, RPU
- ISD 2013+
- Project Category: Appendix B currently
  - Pending Cost Allocation Determination
  - Expected to be BRP
- Description
  - Hampton Corner-North Rochester 345 kV 2110 MVA line 46.6 miles $92,734,000
  - North Rochester-Belvidere 345 kV 2110 MVA line 40 miles $79,600,000
  - Belvidere-North La Crosse 345 kV 2110 MVA line 40 miles $79,600,000
  - North Rochester- 345/161 kV 448 MVA transformer $3,800,000
  - North La Crosse- 345/161 kV 448 MVA transformer $3,800,000
  - North Rochester-Northern Hills 161 kV 302 MVA line 12.1 miles $13,068,000
  - North La Crosse – North La Crosse tap 161 kV double circuit 1 mile $800,000



- Justification:
  - Resolves NERC Standard issues in Rochester, MN and La Crosse, WI areas which are southeast of Minneapolis/St. Paul
    - Rochester area
    - La Crosse area
  - Multiple Category B events
  - Multiple Category C events
- Disposition
  - Expect to move to Appendix A as recommended project at a later date
  - Expect to allocate costs under Attachment FF
  - Will hold stakeholder meetings to fully describe justification and cost allocation when proposed cost allocation determined

P1203 Brookings, SD to Twin Cities 345 kV line

- Estimated Cost: $494 million
- Zones/Transmission Owners: XEL, GRE
- ISD: 2012+
- Project Category: Other (Pending Tariff Treatment)
- Description
  - Brookings County-Lyon County 345 kV 2066 MVA line 49 miles $39,200,000
  - Lyon County-Franklin 345 kV 2066 MVA double circuit line 44 miles $52,800,000
  - Franklin-Helena 345 kV 2066 MVA double circuit line 67 miles $80,400,000
  - Helena-Lake Marion 345 kV 2066 MVA line 16 miles $12,800,000
  - Lake Marion-Hampton Corner 345 kV 2066 MVA line 18 miles $14,400,000
  - Lyon County-Hazel 345 kV 2066 MVA line 22 miles $18,480,000
  - Brookings County- 345/115 kV 448 MVA transformer $6,000,000
  - Lyon County 345/115 kV 448 MVA transformer $6,000,000
  - Hazel 345/230 kV 336 MVA transformer $6,000,000
  - Hazel 345/230 kV 336 MVA transformer $4,000,000
  - Franklin 345/115 kV 448 MVA transformer $4,000,000
  - Lake Marion 345/115 kV 448 MVA transformer $6,000,000
  - Hazel-Minnesota Valley 230 kV 388 MVA new line 8 miles $3,600,000
  - Brookings County-Yankee 115 kV 310 MVA new line 14 miles $7,000,000



- Justification
  - Provides for reliable delivery of generation to meet forecast load growth and support Renewable Portfolio Standard (RPS) requirements
- Disposition
  - Evaluating appropriate treatment under Midwest ISO tariff (e.g., RGIP, GIP, RBP, BRP)
  - Expect to allocate costs at a later date
  - Will hold stakeholder meetings to fully describe justification and cost allocation when proposed cost allocation determined

P973 Big Stone II Transmission

The Big Stone II generator interconnection project has not yet completed its Interconnection Agreement at the time of this MTEP 07 report, and therefore is listed as an Appendix B project. However, the transmission associated with the Big Stone II generator outlet has been included in modeling for determining reliability needs in the MTEP 07 2013 and 2018 models as well as in other Midwest ISO planning models. This was done because the project was nearing execution of the Interconnection Agreement at the time the MTEP 07 studies commenced, and because the

Midwest ISO believes that this transmission will be used and useful regardless of whether the Big Stone II generator project is completed. This transmission consists of the following facilities:

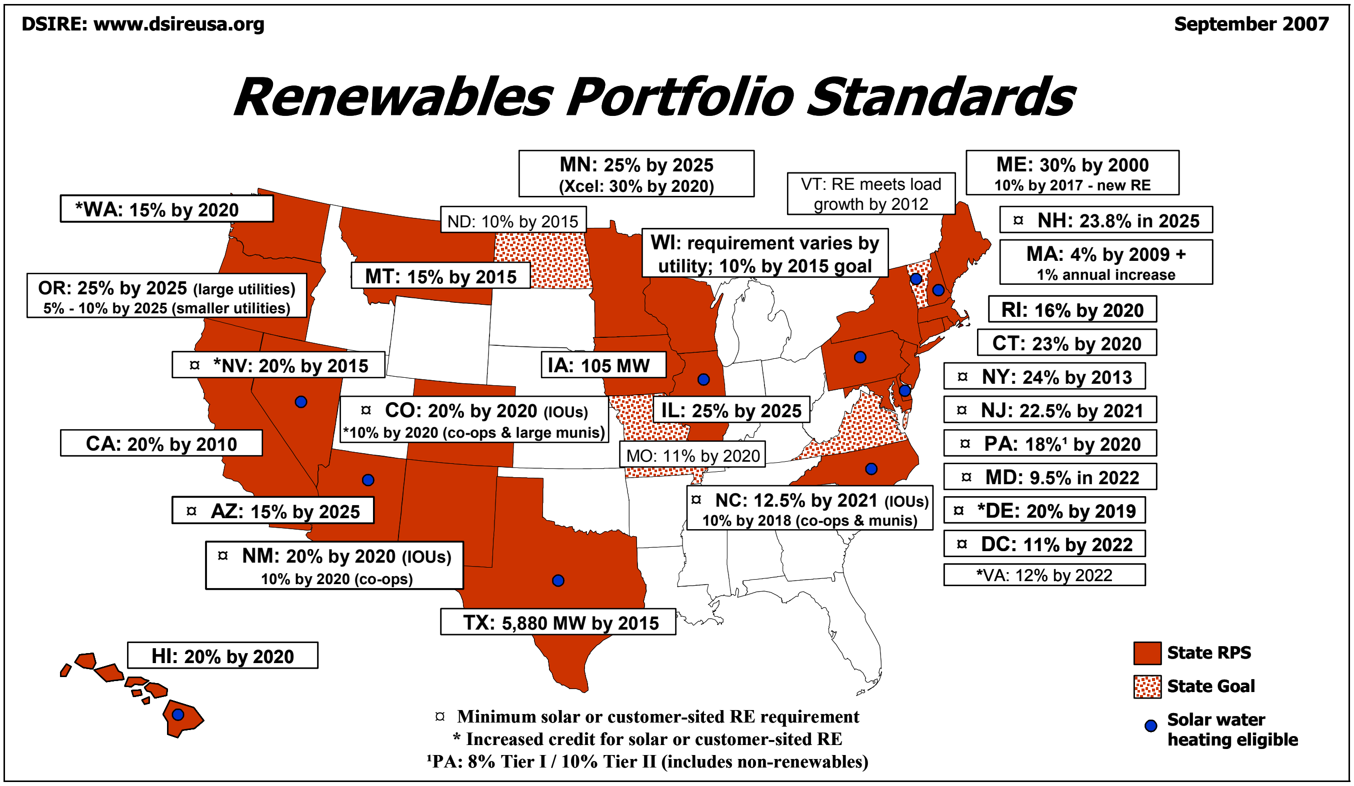
- New Big Stone - Ortonville 230 kV line
- Convert Ortonville - Johnson Junction 115 kV line to 230 kV
- Convert Johnson Junction - Morris 115 kV line to 230 kV
- Install a new Johnson Junction 230/115 kV transformer
- Replace existing Morris 230/115 kV transformer
- Build New Big Stone - Canby 230 kV line
- Convert existing Canby - Granite Falls 115 kV line to 230 kV
- Install a new Canby 230/115 kV transformer
- Upgrade existing Big Stone - Browns Valley 230 kV line

1.3 The Planning Context for MTEP 07

MTEP 07 is a transitional MTEP report. It isolates on those upgrades that are driven almost exclusively by peak load period transmission capacity needs to reliably serve load during those relatively few peak demand hours of the year. These are the traditional "must-do" projects needed to "keep the lights on". While this infrastructure is essential for reliability, and will also provide for some level of improved efficiency of market operations, it is not designed using tools that comprehensively address maximizing total value of transmission investment, generation investment, and energy costs. As a consequence, the sum total of these expansions, while impressive in total investment terms, is likely not sufficient to provide for near optimal levels of investment. However, the Midwest ISO approach to transmission planning is undergoing fundamental and significant changes. These changes are a response to not only the Midwest ISO energy market, but to evolving energy policy related decisions at both the federal and state levels, FERC initiatives to promote improved regionally coordinated planning, and developing structures for more equitable transmission pricing policies.

State and Federal Energy Policy

State and federal energy policy actions aimed at advancing energy independence and efficiency and reducing the environmental impacts of energy supply will require the development of high voltage electric transmission infrastructure that can support these objectives. The States have taken a lead in promoting renewable energy policy. Twenty two states have either Renewable Portfolio Standards or Mandates, and four others have voluntary guidelines or goals along similar lines.



In addition, in August 2007, the US House of Representatives passed a far-reaching package of energy legislation that would promote conservation and the use of renewable resources, including a provision that would require that 15 percent of electricity from private utilities come from solar, wind or other renewable energy sources.

The Department of Energy released its National Electric Transmission Congestion Study in August, 2006, in response to the EPACT 2005, in which they identified several areas of congestion. Two areas within the Midwest ISO among others nation-wide described as "Conditional Congestion Areas" were

- Dakotas-Minnesota (wind)
- Illinois, Indiana and Upper Appalachia (coal)

The report described these as "areas where there is some transmission congestion at present, but significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity." Also stated was the DOE belief that "affirmative government and industry decisions will be needed in the next few years to begin development of some of these generation resources *(in these areas)* and the associated transmission facilities."

FERC Order 890

The FERC has continued to promote efforts amongst Transmission Providers to provide more open and transparent planning processes that enable the needs of customers to be more fully integrated into planning decisions. In the Final Rule, Preventing Undue Discrimination and Preference in Transmission Service, the Commission requires that Transmission Providers participate in a coordinated, open and transparent planning process on both a local and regional level. Further, each Transmission Provider's planning process must meet the Commission's nine planning principles: Coordination; Openness; Transparency; Information Exchange; Comparability; Dispute Resolution; Regional Participation; Economic Planning Studies; and Cost Allocation. During Technical Conferences held throughout the country in 2007, the commission staff emphasized the need for regional coordination in order that transmission planning consider plans of wide enough scope to efficiently incorporate the needs and benefits of the maximum number of customers. It was described by participants that the 500 kV network of the southeast was developed in such a coordinated manner with participants recognizing and demonstrating the mutual values of regional transmission.

The Final Rule notes that "The coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis." The Commission noted the intent of its coordination policies to support the congestion relief efforts of the DOE in stating that "new section 217 of the FPA requires the Commission to exercise its jurisdiction in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of LSEs. A more transparent and coordinated regional planning process will further these priorities, as well as support the DOE's responsibilities under EPAct 2005 section 1221 to study transmission congestion and issue reports designating National Interest Electric Transmission Corridors and the Commission's responsibilities under EPAct 2005 section 1223."

The Final Rule references the final report in 2005 of the Transmission Infrastructure Forum of the Consumer Energy Council of America (CECA), in which CECA concluded that regional transmission planning is needed to ensure the development of a robust transmission system capable of meeting consumer needs reliably and at reasonable cost over time. The CECA Report stresses that regional transmission planning must address inter-regional coordination, the need for both reliability and economic upgrades to the system, and critical infrastructure to support national security and environmental concerns.

Transmission Pricing Structures

The FERC has been promoting for several years the equitable transmission cost assignment for new transmission construction both within RTOs and for Transmission Providers in general. With respect to the Midwest ISO, the Commission ordered the Midwest ISO to pursue alternative cost allocation policies in response to the Midwest ISO 2004 compliance filing of the generation interconnection Order 2003. This Order led to the development by the Midwest ISO of the RECB initiative to develop a comprehensive cost allocation policy addressing all new transmission upgrades. On a parallel path, the commission ordered the Midwest ISO and PJM in the 2004 RTOR Order to develop an inter-regional or "cross border" cost allocation mechanism for new upgrades that recognized the benefit to one RTO of upgrades developed in the other.

1.4 Response to Policy Shifts

Value-Based Planning Initiative

Current Midwest ISO planning processes are comprehensive and comply with the Commission's planning principles of Order 890. Planning is open and transparent, and improving in those aspects, and coordinates both internally and externally with planning processes of other entities. However, these open processes are only as effective as the assumptions and methods that they encompass. In that regard, the Midwest ISO continues to search for innovative ways to best address infrastructure needs of the competitive bulk power market and to allocate costs fairly amongst those who cause the problem as well as to those who will benefit from the solution, and so that there are adequate incentives for transmission construction.

Over the past two years, the Midwest ISO has been moving to a long-term value-based transmission expansion planning model. That model will seek to extend the planning horizon to reflect appropriate project time scales, develop and articulate the comprehensive value of a transmission project or portfolio of projects, develop political consensus on value attributes, identify transmission infrastructure which maximize this value within the Midwest ISO footprint, and provide for balanced cost sharing under the tariff.

To reveal transmission infrastructure's value, transmission planning must extend its analysis to include more than the minimum capacity required to maintain reliability. The recognition of benefits that include reducing the delivered cost of energy and access to varied generation sources needs to be assessed and quantified. The 2008 planning cycle, will provide a further step towards this goal. As part of the MTEP 2008, the Midwest ISO is focusing on identification of short, mid and long-term planning solutions to work through the transition from a shorter term, reliability based methodology to value-based planning, which by nature is longer-term.

Integration of Interconnection and Long-term Planning Processes

There is a natural and inseparable intertwining of planning for long-term load growth, and for interconnection of new generation. This is true despite the fact that as a consequence of the Open Access Order 888 in 1996, these two processes have been forced apart to accommodate the need to fairly interconnect independent suppliers. The separation of these processes was necessitated by the separate competitive supply positions, business objectives, and plans of the independent supplier and the integrated Transmission Provider at the outset of implementation of Order 888 and its follow-on Order 2000 addressing generator interconnections. Melding together the independent decisions of a multitude of independent suppliers and load serving entities into a cohesive and efficient transmission infrastructure remains a puzzle that the industry continues trying to solve.

The Midwest ISO believes that the RTOs are uniquely positioned to reintroduce the cohesion in generation and transmission planning that has been stretched since the open access rule. We and our stakeholders have lived through the effects of this separation and experienced first hand the difficulty and frustration of trying to at once achieve fast, effective, and fair generator interconnections, while developing an efficient forward looking long-range transmission plan. These difficulties have been the result of some growing pains surely, but at the core we believe are the result of essentially adopting the pro-forma procedures enacted in Order 2000 to ensure fair and comparable interconnection service, and applying them to the high volume of interconnects the RTO must deal with. The advantage of the broader regional focus of the RTO is frustrated by the pro forma procedures, the sequential nature of which does not lend itself to any kind of efficiency of scope.

Much as we have tried improvements to the process such as grouping studies, adjustments to study processes and tweaks to procedures, with the increases in renewable energy mandates and the vast wind resources in our footprint, we are facing an ever steeper challenge to providing acceptable interconnection service. The cumulative effect of dozens of relatively small projects in certain areas has driven the state of the system to the point that large-scale upgrades are needed to interconnect the significant quantity of proposed generation. Transmission facilities required to integrate these resources may span over 100 miles and will likely require transmission facilities with a minimum voltage of 345kV, with higher voltage facilities potentially proving to be optimal. However, current evaluation mechanisms through the Generator Interconnection process often result in building transmission upgrades for generation interconnects on an incremental basis, that are minimally sized so as to limit the upgrade responsibility of the connecting generator to only that which is caused by his interconnection alone. While the aggregate transmission capacity needed to optimally and efficiently accommodate the aggregate amount of expected resources in a given region may be extensive, the assessment of construction costs for a large-sized project suitable in the aggregate power plants that are likely to be developed in these regions can pose too great a financial hurdle for the first generation developer(s). As a result, the network upgrades often forgo economies of scale in an effort to mitigate the up-front transmission costs. This piecemeal process is repeated for subsequent generation developers in the same region requiring additional incremental upgrades or even rebuilds of recent small scale upgrades to address their needs.

We seek to resolve this situation in a way that at the same time will reunite the forward load planning for the grid as a whole, with the independent introduction of generation to the grid by suppliers.

The trick is to solve the open access sixty-four thousand dollar question: "where should I locate transmission and of what design, when I don't know where, when or how much generation suppliers will bring on to the grid". The answer comes by linking together the planning analyses that we have been pursuing, until recently, on somewhat separate tracks.

We have recognized that in order to develop efficient transmission expansions, a long term view is needed. There are efficiencies in developing facilities that can move higher volumes of electricity; with respect to right-of-way utilization and in facility costs per unit of power. These facilities take longer to permit and develop, and so require the longer view. A longer term view cannot be planned for without some assumptions about load and generation. Neither of these is particularly easy to predict, but of the two, load forecasting can be done with less error using traditional methods. Forecasting where the generation may be, its size, operating characteristics and location is difficult and has a significant element of risk. However, this is a risk that must be accepted, unless we are willing to live with the costs that result from repeated increments of small upgrades to the transmission grid and the limitations that that process places on the ability to introduce new generation effectively.

Thus in our MTEP 08 process, we have begun to develop assumptions about what and where the generation will be that will come on the grid to serve the long-term load forecast needs. To a degree, the transmission that is developed will have some influence on what generation will be built, just as the lack of transmission has a profound influence on that same question. But if the transmission developed to support those generation assumptions is substantial enough, and developed to accommodate a number of possible future scenarios that will influence generation decisions, and also considers the available input from load serving entities, and the current interconnection queue activity, the transmission investment will be aligned with generation needs. The amount of error introduced by the uncertainties in planning for long-term transmission expansion we believe will be offset many times over by energy supply savings from the generation integration options that it will provide for; including the option to not have to develop as much generation by better capturing diversity of generation availability. We will endeavor to demonstrate these assertions in our MTEP 08 planning effort, and beyond.

A key aspect to developing the future generation assumptions is to capture the drivers for generation development, and link those to the physical energy resources in and around the Midwest ISO. When we associate the long-range transmission needs with emerging generation activity in the interconnection queue, we can link the ridged interconnection procedures with the long-term expansion planning process. This permits the assignment of a portion of transmission development cost responsibility to both the new generators coming on line that benefit from the planned expansions, and to the loads that will need the transmission to deliver generation supplies they choose to contract with or develop. This is the essence of the new Midwest ISO proposal to provide for “Open Season” generation interconnection wherein the transmission expansions to accommodate generation interconnections are sized to conform with the long range plan, which in turn has been developed considering the likely future generation interconnections. As the interconnections materialize, the transmission costs are apportioned between the generators and the loads, but the transmission is sized for the long haul.

The Midwest ISO is currently working with stakeholders to establish a new category of Network Upgrades referred to as a Regionally Planned Generation Interconnection Projects, or RPGIP. A RPGIP is defined as a Network Upgrade consisting of one or more transmission facilities that are needed to interconnect large concentrations of location-constrained resources, and that are sized to accommodate anticipated interconnections that will be using the upgrades based on current queued requests, long-term portfolio standard requirements, and assessment of other drivers of future capacity needs. More simply put, a RPGIP would be identified through the annual MTEP long-term planning process. That project would then be made available on a subscription basis through the Generator Interconnection process to all generators in the area, with costs shared on a pro-rata basis. The principles of cost causation and the net allocation of the costs between load and generation would remain the same as those accepted by the stakeholders during other revisions to the Midwest ISO Tariff. In addition to improving the general progress of generation projects through the interconnection queue, the Midwest ISO believes that this approach will help to facilitate more economical development of network upgrades to support generation interconnects by aligning the short term actions with long-term plans. This concept is in development with stakeholders and we hope to turn it into a tariff revision in the near future.

Transmission Backbone Initiatives (ITC/AEP/MISO/PJM)

The Midwest ISO proposed some very early “backbone” transmission plans back in MTEP 03 that we referred to as “The Vision Plan”. The effort was intended to demonstrate at a high level the potential for economic value of truly regional high voltage transmission connections. Since that time, work has continued by the Midwest ISO in refining our analysis tools and techniques as we have described. We have continued to consider variations on these original concepts to see if they can be justified as solid recommendations for substantial improvements in the transmission grid of the Midwest ISO.

At the same time, various Midwest ISO and neighboring transmission organizations have been working in coordination with the Midwest ISO to advance sub regional aspects of the Midwest ISO backbone plan, and interconnection with similar improvements being evaluated in adjacent regions. In particular, American Electric Power (AEP) and International Transmission Company (ITC) have been evaluating a 700 mile EHV transmission project that the parties have stated would connect to existing AEP high voltage systems in the southwest corner of Michigan and in Ohio and would establish a regional transmission corridor capable of improving electric reliability, relieving power congestion, enhancing market access to the grid, and aiding in more efficient distribution of current generation.

The sub regional transmission plan has been shared with the Midwest ISO and PJM for additional analysis. The Midwest ISO is committed to working with these parties to realize the potential value that these plans may provide.

RTO Coordination Efforts

The Midwest ISO and PJM are broadening that effort in order to provide for a well integrated evaluation that also coordinates with analysis by SPP, TVA, and the DOE. These parties are discussing the undertaking of a joint coordinated system plan that would evaluate these overlay concepts further during 2008. The Midwest ISO has various joint coordination agreements with PJM, SPP, TVA as well as with other entities. Each of these transmission providers have been evaluating the value and effectiveness of several alternative high voltage backbone plans

In an effort to better coordinate these efforts, the Midwest ISO, PJM, SPP, and TVA intend to hold a stakeholder meeting in the fourth quarter 2007 to announce a Joint Coordinated System Plan. This plan will build upon the internal initiatives of each of these transmission entities and has as its goal to advance the understanding of the benefits of a series of high voltage regional expansions that once completed would create a super-highway of extra high voltage transmission that would link the resources and loads across a multi-state area from North Dakota to Pennsylvania and points south impacting 400,000 MW of customer demand. Stakeholders will be invited to provide input to and help shape the scope and ongoing work of this joint study effort to maximize its value to stakeholders.

The Cost Allocation Challenge

The reliability project cost sharing procedures, commonly known as RECB I, were filed with FERC on October 7, 2005 and conditionally approved by FERC on February 3, 2006. A cost sharing methodology for Regionally Beneficial Projects, commonly known as RECB II was filed on November 1, 2006, and will be applied to eligible projects beginning with MTEP 08.

The RECB process ultimately identified two drivers, production cost and Load LMP savings, as the basis for both project inclusion and cost allocation for economic projects. However, observers agree that there are value drivers for transmission infrastructure that are not captured in the initial benefits identification protocol. Contained in the RECB II filing is the notion that as experience with the initial protocol and additional value driver analytics mature, tariff filings to adjust or amplify the inclusion criteria and minimum benefits threshold are expected. These additional value drivers might include generation reserve margin considerations, fuel diversity considerations, reliability considerations and national and state energy policy goals, and risks to implementation to name some that warrant consideration.

Work is underway with the PAC, OMS and other interested stakeholders to more comprehensively define the value measures that may be used both in assessing transmission plans against alternatives and in allocating costs appropriately across an increased set of benefit drivers. The work to identify incremental value drivers and how they are assessed against transmission projects will be ongoing throughout 2007 and into 2008. Subsequently, stakeholder discussions will begin on how to use these criteria both for inclusion and cost sharing of transmission expansion projects.

A related effort by the Midwest ISO Transmission Owner community on what is termed a “Day 3” tariff, has recently had comments filed with the FERC. Section II.B of Appendix C to the TOA envisions replacing the license plate tariff if a consensus could be formed by the Transmission Owner community after the 6-year “Transition Period” following the transfer of transmission assets to the Midwest ISO. The resolution of this process at FERC may result in impacts to either the existing cost sharing mechanisms, or the approach by which the additional value measures are integrated into the current cost sharing methodologies.

Overall, the Midwest ISO has moved the ball forward considerably in establishing cost sharing mechanisms for projects driven primarily by reliability, as well as for more regionally beneficial projects founded on economic benefits. As we have expressed to the FERC in these filings, we will continue to report to the FERC on the effectiveness of these efforts to provide incentives for the construction of needed transmission and to equitably allocate costs on the basis of both cost causation and beneficiary considerations. We are also nearing resolution of cross border cost allocations with PJM for reliability projects, and as PJM will be establishing its internal proposal for dealing with economic projects, expected to be along similar lines as those of the Midwest ISO, we expect to reestablish joint stakeholder discussions to address cross border treatment of economic projects early in 2008.

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Section 2.0 Midwest ISO Planning

The Midwest ISO Transmission Expansion Plan (MTEP) has three primary objectives. One objective is to perform a reliability assessment of the Midwest ISO integrated transmission system. A second objective is to review Transmission Owning members transmission plans and make sure that appropriate projects are reviewed and recommended to Midwest ISO Board of Directors for Approval. The third objective is to develop transmission upgrades to improve market performance. MTEP 2007 (MTEP 07) is an incremental reliability study which address the first two objectives. The third objective is presently under analysis as part of MTEP 2008 study. This section describes how the MTEP study meets these objectives.

2.1 MTEP Planning Regions

To manage the production of the MTEP study, Midwest ISO transmission system is divided into three Planning regions. The Planning regions were based on existing Midwest ISO Operating regions. The MTEP Planning regions differ from the Midwest ISO Operating regions in that the American Transmission Company is in the West Planning region, but it is in the East Operating region. Midwest ISO Staff members were assigned to lead planning of each of the regions. Midwest ISO Transmission Owning members and other interested stakeholders participated in the study.

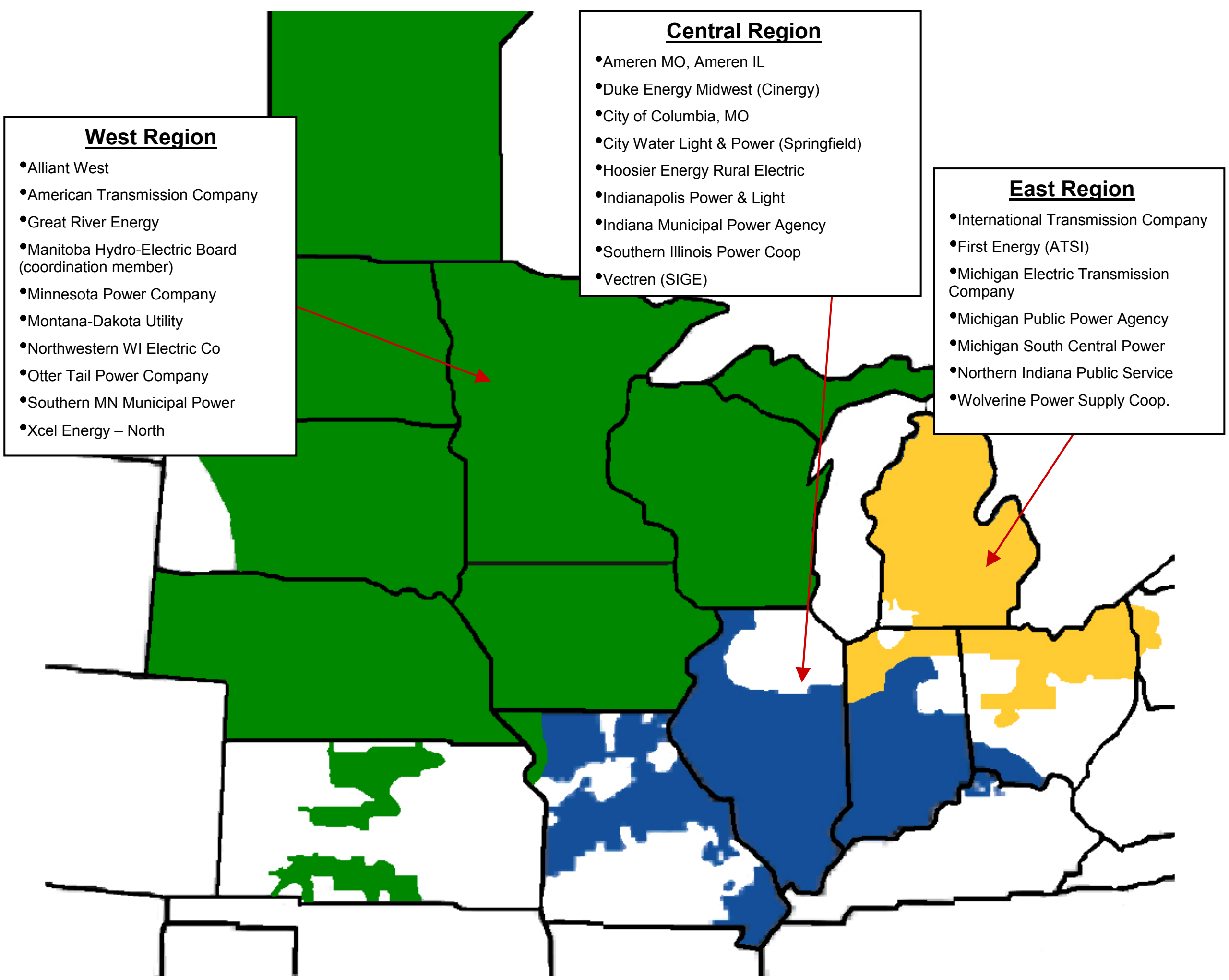

Figure 5.1-1: Midwest ISO Planning Regions

The Expansion Planning Group (EPG) was the primary group involved in the technical studies. The EPG documented the study criteria and defined study methodologies; provided, reviewed and updated models; produced contingency and monitored element files; and were generally the first to review the results produced by Midwest ISO Staff. Note that most transmission planning studies were performed in a collaborative process. The EPWG also provided feedback and recommendations to Planning Subcommittee on how to address technical planning issue.

The Planning Subcommittee (PS) stakeholder group reviews MTEP analysis and reports. Review of cost allocation of projects recommended for Midwest ISO Board of Director approval via MTEP study is done by the Planning Subcommittee. The Planning Subcommittee reports to the Planning Advisory Committee.

2.2 MTEP07 Baseline Reliability Assessment

The reliability assessment tests the existing plan using appropriate NERC Table 1 events, determines if the system as planned meets TPL standards, develops and tests additional transmission system upgrades to address the identified issues, and then tests the performance of the final plan. The final plan is then documented and provided to Regional Reliability Organizations. The NERC TPL Standards can be found on the NERC website at: http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html This section provide additional detail on the assessment process.

2.2.1 Planning Methodology Overview

The baseline reliability analysis provides an independent assessment of the reliability of the currently planned Midwest ISO Transmission System for the years 2013 and 2018 to cover near-term and long-term planning horizon. This is accomplished through a series of evaluations of the 2013 system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to ensure that the transmission system upgrades are sufficient and necessary to meet NERC and regional planning standards for reliability. This assessment is accomplished through steady-state powerflow, dynamic, generation deliverability, and voltage-stability analysis of the transmission system performed by Midwest ISO staff and reviewed in an open Stakeholder process. The current assessment focused on performance of the 2013 system during summer peak operating conditions with some 2018 summer peak analysis for marginal issues identified in 2013 case. Dynamic simulations examined a 2013 summer shoulder (70% load) system condition which is a more stressed case appropriate for dynamic simulations. These are the critical system conditions. Small-signal stability and load deliverability were performed in prior MTEP study and will be performed again in subsequent MTEP studies. MTEP reliability assessments will performed annually starting with MTEP07.

The initial phase of the Baseline Reliability analysis determined if the projects in the expansion plan provide adequate system reliability. All projects with Planned or Proposed planning status were included in the initial models. Some projects were not included, if there was desire to revalidate the need for the project. NERC category A, B, C, and D events were analyzed using steady-state, voltage stability, generation deliverability and dynamic stability analysis. Planning criteria issues (thermal overloads and low or high voltages) were flagged using Transmission Owner's design criteria limits. Transmission solutions were developed in collaboration with Transmission Owners to address system needs identified in initial analysis and tested by Midwest ISO staff for effectiveness. These plans are contained in Appendix A, B and C of this study and expected in-service dates or schedule for implementation.

Also during initial phase of the Baseline Reliability analysis, the Expansion Planning Group reviewed operational issues associated with transmission service requests (TSR) by examining historical transmission line loading relief (TLR) requests and real-time bound constraints during two years of market operation. Operational issues that will be addressed by the expansion plan were documented. A voltage stability analysis of a variety of transfers on top of the 2013 summer peak condition was performed to determine areas that may have voltage stability issues and which are being further evaluated in continuing studies.

The final step in the Baseline Reliability analysis adds the projects identified to meet identified system needs through the 2013 to 2018 period. The critical analyses were repeated to confirm the Planned and Proposed projects in the Baseline Reliability transmission expansion plan provide adequate system reliability. The projects in the current transmission plan, which are the result of the transmission studies, are listed in Appendix A (projects recommended by Midwest ISO staff for approval by Midwest ISO Board of Directors), Appendix B (projects which may require additional analysis and review before being submitted to Board for approval or have adequate lead time to enable refinement to the project), and Appendix C (candidate projects submitted by TO's to address identified issues).

The primary inputs and assumptions for the Baseline Reliability analysis are:

1) the transmission system condition to be modeled and analyzed with associated load, generation and base interchange values;
2) the contingencies and system events to be analyzed;
3) the facilities monitored with respect to the Planning Criteria; and
4) the current transmission expansion plans from the planning process.

Planning criteria, models, and contingencies are discussed in the following sections. Section 6 provides summary of the results of these analyses.

2.2.2 Planning Criteria and Monitored Elements

In accordance with the Midwest ISO Transmission Owners Agreement, the Midwest ISO Transmission System is to be planned to meet local, regional and NERC planning standards. The Baseline Reliability analysis performed by the Midwest ISO staff in this plan tested the performance of the system against the NERC Standards, leaving the compliance to local requirements to the Transmission Owners where those standards may exceed NERC standards. The specific branch loading and bus voltage thresholds of our member's criteria (local flagging criteria) were applied to accurately reflect the different system design standards of our members in this assessment.

All system elements 100 kV and above within the Midwest ISO Planning regions as well as tie lines to neighboring systems were monitored. Some non-Midwest ISO member systems were monitored if they were within the Midwest ISO Reliability Coordination Area. See Appendix D6 for Monitored element files.

2.2.3 Baseline Models

The plan year for a majority of the baseline reliability analysis is 2013. The 2013 summer peak condition was selected to enable comparison of expansion plan developed using traditional methodology in MTEP07 with the enhanced methodology which includes economic studies from next year's MTEP08 study. Therefore, for MTEP07, a 6-year out transmission system performance of the Baseline Reliability Plan was developed. The Midwest ISO Baseline Reliability study models for 2013 summer peak and 2018 summer peak were developed by incremental updates to the models used in MTEP06. External region updates were applied along key seams. Forecast network resources (generation) and loads were validated. The steady-state powerflow analysis examined the system performance for summer peak conditions with expected firm transfers modeled.

Model Assumptions

Transactions

Contractual dispatch case will have all Firm drive-within, drive-in, drive-out, drive-through, and other external transactions modeled. (i.e. reflects original FIRM transactions modeled in the NERC base case (starting case) and subsequent changes to the transactions list through the MTEP model review process). Virtual transactions and fake generators were removed and replaced with proxy generators from MTEP08 Reference future. The decision to replace virtual transaction with proxy generators results in a baseline reliability model which has reduced system transfers caused by the virtual transactions. Removal of virtual transaction reduces the occurrence of reliability issues being identified on neighboring system as a result of the virtual transaction. However, the proxy generators may cause or mask issues on the system which is deficient in generation during the plan year. Impacts of proxy generators are discussed in Section 6 of the report.

2018 summer peak and 2013 summer off-peak (70% load) have security constrained economic dispatch within Midwest ISO, therefore, these cases will not include any explicit Midwest ISO internal transactions (drive-within) modeled but will retain the firm transactions to external parties modeled in the contractual dispatch case.

Losses

The powerflow models used determine control area losses and adequate generation is dispatched to cover transmission system losses and previously specified firm transactions. .

Load

Three different system load conditions were analyzed in MTEP07: 2013 summer peak demand with a 50/50 load forecast by control area; 2018 summer peak demand, and 2013 summer off-peak, 70% load (also called summer shoulder). Load forecasts in the models include existing demand side management and conservation programs.

Generation

A key assumption in transmission planning studies is the generation dispatch. MTEP 07 study analyzed two dispatches: Contractual Blended Dispatch (contractual dispatch) for 2013 summer peak and Security Constrained Economic Dispatch (SCED) for 2018 summer peak and 2013 summer off-peak. The Contractual Dispatch is similar to traditional control area dispatch in that Load Serving Entities' designated resources are dispatched to meet their loads. The Blended in Contractual Blended dispatch implies that a couple areas are short generation during this period, therefore, generators from MTEP08 Reference generation portfolio (future) were included in those control areas to provide adequate level of generation resources. Analysis of Contractual Dispatch case drives reliability issues and supports development of the transmission system to support Financial Transmission Rights in the market. Future generators with signed Interconnection Agreements were modeled. Proxy generators were modeled in several control areas.

Reactive Resources
Powerflow models used in the analysis contain existing and planned reactive resources. Specifically, generator reactive capabilities, fixed shunt capacitors, switched shunt capacitors, synchronous condensers, static var compensators, and other var sources. Note that only on-line generators will provide reactive support according to controls.

Control Devices
Powerflow models contain existing and planned control devices, such as, load-tap changing (LTC) transformers, phase angle regulating transformer controls, generator voltage controls, area interchange controls, Direct Current line controls, and switched shunts controls.

Model Topologies
The different model phases reflect different topologies dependent on which future projects were included in the models. The transmission system topology contains existing and planned transmission facilities. Future facilities with expected in service dates after summer 2013 or 2018 were not modeled in the respective models.

Baseline Reliability Plan 2013 summer peak **Initial** models contained a majority of Appendix A and B projects. The Initial model contained 515 future facilities. Some Appendix B projects where moved to Appendix C for additional review and were not included in initial model to provide an additional demonstration of project need. Note that not all proposed projects are modeled, so there is a lower percentage of Appendix B projects in the Initial model.

Baseline Reliability Plan 2013 summer peak **Final** model contains all Appendix A and B projects required to meet identified system reliability needs of Table I for Category A and B, and relevant Category C issues. The Final model contained 603 future facilities. This model is used to validate that the Baseline Reliability Plan works well together and identify any outstanding issues which require resolution. See Appendix D5 for modeled future facility documentation applicable to all MTEP 07 Baseline Reliability Plan models.

2.2.4 Contingencies Examined
Regional contingency files were developed by Midwest ISO Staff collaboratively with Transmission Owner and Regional Study Group input. NERC Category A, B, C and D contingency events on the transmission system under Midwest ISO functional control were analyzed. In general, contingencies on our members' transmission system at 100 kV and above were analyzed, although some 69 kV transmission was also analyzed. Approximately 11,000 NERC Category B (single line, single transformer, or single generator outage) contingency events were analyzed in AC contingency analysis. Approximately 4,800 explicitly defined NERC Category C (double circuit tower, breaker fault/failure, bus fault and double element outages including double generator outages) contingency events were analyzed. Approximately 58,000 automated double contingencies were analyzed in AC contingency analysis. In general, automated double branch contingencies for branches greater than 200 kV were run by control area and included ties lines to neighboring control areas. Select automated doubles on the 100 kV to 199 kV system were also analyzed. The automated double contingencies are more severe than NERC Category C3 events and also capture some C1, C2, and C5 events. Where Midwest ISO and non-Midwest ISO systems were highly integrated, contingencies on non-Midwest ISO systems were also analyzed for impacts on the Midwest ISO members' systems. There were approximately 4,500 Category D events analyzed. There were 292 NERC Category A, B, C and D events studied with dynamic stability simulations. In total, approximately 79,000 contingency were analyzed in initial MTEP07 contingency analysis.

A NERC Category C3 event is defined as a Category B event, followed by manual system adjustment, followed by another Category B event. In MTEP process, two Category B events are analyzed (automated doubles) without the allowed manual system adjustment between the two events. NERC Planning Standards allow Category C analysis to focus on the most severe events. Midwest ISO requested that its members draw on their past studies and system knowledge to provide the severe Category C events. Those events were analyzed in this study. Midwest ISO expects that the selection of contingencies to be studied in any one MTEP will vary, so that over several MTEP studies, all areas of the system will be thoroughly tested. Midwest ISO also expects to add additional contingencies as we move forward based on our own operating and planning experience. In addition, Midwest ISO staff performed independent screening analyses of multiple element outage events to help identify areas potentially vulnerable to voltage instability.

2.3 Determination of New Appendix A Projects - Approved Projects

In a parallel effort to the baseline reliability assessment, Midwest ISO staff reviewed existing projects to determine which should be moved from Appendix B to Appendix A. Need timing was estimated from MTEP reliability analysis. Lead times for projects construction was also estimated. A preliminary list of projects was prepared by Midwest ISO staff and reviewed with Transmission Owners to confirm that our estimates were appropriate in light of any additional information they may have on project drivers and leads times.

After finalizing the list, detailed project reviews and justifications were prepared by Midwest ISO staff for projects eligible for regional cost sharing under Attachment FF of Midwest ISO Energy Markets Tariff (EMT). The project justifications were reviewed at Expansion Planning Group and Planning Subcommittee meetings. Project justifications for all new Appendix A projects are in Section 5. Cost allocations were determined for eligible projects using the MTEP07 Final Plan model for 2013. Cost allocations were presented at Planning Subcommittee meeting for review prior to a final Cost Allocation review meeting. The cost allocation process is described in the next section.

2.4: Cost Allocation

2.4.1: Cost Sharing of MTEP Projects

MTEP 07 marks the second regional expansion plan under which cost sharing for eligible transmission expansions is in effect. The eligibility criteria for sharing are described under Attachment FF of the Energy Market Tariff (EMT) which identifies the following types of transmission expansions.

1. Baseline Reliability Projects (BRP)

Baseline Reliability Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization ("ERO") reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable to the Transmission Provider. Baseline Reliability Projects need to meet the cost thresholds specified in Attachment FF in order to be eligible for cost sharing.

2. Transmission Access Projects (TAP)

Transmission Access Projects are derived from the Generator Interconnection study process as Generator Interconnection Projects (GIP) and Transmission Service Request study process as Transmission Delivery Service Projects (TDSP) which are described below.

a) Generation Interconnection Projects (GIP)
Generation Interconnection Projects are Network Upgrades associated with interconnection of new, or increase in generating capacity of existing, generation under Attachments X and R to the Tariff. These projects are driven by interconnection study procedures and agreements. The cost of Network Upgrades is shared 50/50 between Interconnection Customer and Pricing Zones. For interconnection customers interconnecting to American Transmission Company (ATC LLC) transmission systems and meeting certain eligibility requirements, 50% of the Network Upgrade cost is allocated entirely to ATC LLC pricing zone and the remaining 50% is allocated to affected pricing zones based on sub-regional and/or postage-stamp allocation rules described under Attachment FF[1]. A similar treatment is applicable to interconnection customers interconnecting to ITC/METC transmission systems and meeting certain eligibility requirements[2].

b) Transmission Delivery Service Projects (TDSP)
Transmission Delivery Service Projects are Network Upgrades driven by Transmission Service Request (TSR) study procedures and agreements. These upgrades are needed to provide for requests for new Point-To-Point Transmission Service, or requests under Module B of the Tariff for Network Service or a new designation of a Network Resource. Cost of these upgrades are either directly assigned or rolled-in as per Attachment N of the EMT.

3. Regionally Beneficial Projects (RBP)

Regionally Beneficial Projects are Network Upgrades that meet the inclusion criteria and cost thresholds defined in Attachment FF and are not determined to be either a Baseline Reliability Project or a Transmission Access Project. Eligibility for cost sharing as a RBP is determined based on benefit metrics reflective of savings in Adjusted Production Costs (APCs) and the reductions in load energy payments resulting from Locational Marginal Price (LMP) changes, caused by the RBP.

4. Other Projects

Other projects are defined as projects that are not covered by the project categories described above but are included in an MTEP report. These could include, (i) Transmission Owner initiated reliability projects driven by local reliability planning criteria, (ii) Transmission Owner initiated economic projects that do not meet Attachment FF economic inclusion criteria, and (iii)Transmission Owner initiated projects that may prove to be RBP or cost shared BRP but for which the Midwest ISO has not yet determined the cost sharing of, but that the Transmission Owner requires (for state regulatory proceedings or other cost recovery reasons under the Tariff) be included in the MTEP. The cost responsibility for these “Other Projects” is per the ISO Agreement through Attachment O recovery until such time as the Midwest ISO were to complete analyses sufficient to reclassify the project(s) as an RBP or BRP with other appropriate cost sharing methodologies.

[1] 120 FERC 61221 (2007) order conditionally accepting ATC LLC's proposed tariff revisions to Att FF (ER07-1144-000)

[2] 120 FERC 61220 (2007) order accepting ITC’s proposed tariff revisions to Attachment FF (ER07-1141-000)

2.4.2 MTEP07 Cost Shared Projects - Summary

There are twenty eight (28) projects recommended for approval as part of MTEP07. Thirteen (13) of these have been identified as Baseline Reliability Projects, Nine (9) as Generator Interconnection Projects, one (1) Transmission Delivery Service Project, and five (5) "Other Projects". No Regionally Beneficial Projects are recommended as part of MTEP07. The total estimated cost of these twenty eight (28), new MTEP07 Appendix A projects is about $246 million.

Out of the thirteen BRPs, six (6) are eligible for cost sharing along with the network upgrades for nine (9) generator interconnection projects. The total estimated cost of the new MTEP07 Appendix A projects eligible for sharing is about $170 million. The pricing zone allocation summary for these fifteen (15) projects is shown in Appendix A-1 of this report.

2.4.3 General Allocation Procedure

Having established the need for the projects and after identifying the transmission expansion projects needed to meet the needs, these MTEP projects are classified into different project types discussed above. The eligibility for cost sharing is then determined after applying the specific eligibility criteria and thresholds for the different project types as defined under the tariff. Below is a high-level description of the methodology used for determining cost allocations for eligible MTEP07 BRP and GIP projects.

For eligible Baseline Reliability Projects involving 100 kV to 344 kV facilities, 100% of the eligible cost is allocated to pricing zones based on a Line-Outage-Distribution Factor (LODF) calculation which determines the sub-regional allocations on pricing zones. LODF is essentially a measure of the electrical proximity of the new project to the pricing zones. The LODF calculation reflects, removing the new facility from the MTEP model and measuring the effects on other facilities in the Transmission System and quantifying the impact in terms of LODF*Miles. Sub-regional percentage share for a given pricing zone is calculated as the relative zonal share of sum of absolute value of (LODF x Miles).

For eligible Baseline Reliability Projects involving 345 kV or higher facilities, 20% of facility cost is allocated on Postage Stamp which is determined based on the load ratio shares from the 12 Coincident Peak Load (12 CPL) values in the Attachment O in effect when the MTEP is approved by the Board. The remaining 80% of the eligible cost is allocated among the pricing zones based on the LODF calculation methodology used for sub-regional allocations.

50% of the cost of Network Upgrades for eligible Generator Interconnection Projects is allocated based on the same sub-regional and/or postage stamp allocation rules applicable for BRPs. In the case of GIPs however, there are no cost or voltage thresholds in order to be eligible for sub-regional sharing. The remaining 50% of the Network Upgrade cost is assigned to the Interconnection Customer except in the case of interconnection customers interconnecting to ATC LLC, ITC, or METC transmission systems and meeting certain eligibility requirements, where the remaining 50% is assigned to the respective pricing zone instead of the Interconnection Customer.

2.5 How Does a Project Get Into MTEP?

There are a couple ways in which projects get into the MTEP Appendices A, B and C. The difference is whether the project is submitted before or after Midwest ISO identifies a need for it. One way is through MTEP study need identification. This happens when Midwest ISO staff identifies a system need during the MTEP system analysis. Midwest ISO Staff would then work collaboratively with Transmission Owners and stakeholders to determine an appropriate solution. The Transmission Owner may have already identified the need and have a recommended solution. If this is the case, the Transmission Owner would submit their recommended project and alternatives for Midwest ISO staff for testing and review for effectiveness in addressing the ultimate solution to the identified need. If a recommended solution did not exist, alternatives would be developed in collaboration with Transmission Owners and tested by Midwest ISO staff. The project is placed into Appendix A or B as appropriate. See additional discussion of Appendix types below.

The second way a project gets into the MTEP is for the Transmission Owner to submit a project for review prior to Midwest ISO staff identifying the need. When this happens the project is placed into Appendix C. Midwest ISO staff would first document the need driver, then review effectiveness of the recommended project. A project would be placed in Appendix B after the need has been identified and effectiveness determined. A project would move into Appendix A after more detailed review of alternatives and Midwest ISO Board of Directors approval.

2.6 MTEP07 Appendices A, B, and C

In MTEP06, the approved transmission expansion plan consisted of the project facilities in Appendix A. MTEP06 had both Appendix A and Appendix B to distinguish between projects which are recommended for implementation and those which require additional planning or review. MTEP07 also has an Appendix C for projects that are proposed for study but have not yet been reviewed by Midwest ISO staff or are in conceptual stages of development. Projects are in Appendix C until they can be moved to Appendix B and Appendix A via the study process which demonstrates need and effectiveness of the project.

Appendix A

Appendix A contains the transmission expansion plan projects which are recommended by Midwest ISO staff and approved by Midwest ISO Board of Director for implementation by Transmission Owners (TO). Projects in Appendix A have a variety of system need drivers. Many of the projects are required for maintaining system reliability per NERC Planning Standards. Other projects may be required for generator interconnection or transmission service. Some projects may be required for Regional Reliability Organization standards for filed Transmission Owner local criteria. Yet other projects may be required to provide distribution interconnections for Load Serving Entities. All projects in Appendix A have a Midwest ISO documented need.

Projects in Appendix A may be eligible for regional cost sharing per provisions in Attachment FF of the Tariff. A project eligible for regional cost sharing per Attachment FF of the tariff must go through the following process to be moved into Appendix A:

- Midwest ISO staff has done an independent need driver validation
- Midwest ISO staff has considered and reviewed alternatives with TO
- Midwest ISO staff has considered and reviewed cost estimates with TO
- Midwest ISO staff has endorsed the project

- Midwest ISO staff has scheduled and held a stakeholder meeting for any such project or group of projects to be cost shared, or other major projects for zones where 100% of costs are recovered under Tariff
- Midwest ISO staff has taken the new recommended project to Board of Directors for approval. Projects are moved to Appendix A via a Board Presentation at any regularly scheduled Board meeting.

Appendix A is periodically updated. That is, recommended projects need not wait for completion of next MTEP for Board approval and inclusion in Appendix A. As projects go through the process and are approved by the Midwest ISO Board of Directors, Appendix A will be updated and posted.

Appendix B

In general, MTEP Appendix B contains projects which are still in the Transmission Owners planning process or are still in the Midwest ISO review and recommendation process. Projects in Appendix B are not yet recommended or approved by Midwest ISO, therefore, projects in Appendix B are not eligible for cost sharing. There may be some potential Baseline Reliability Projects for which Transmission Owners have completed their analysis, but for which Midwest ISO staff has not been able to validate the reliability need or reasonableness of the solution against alternatives, at the present time. The result is that some projects which will become eligible for cost sharing are at this time not yet "ready" for Midwest ISO recommendation and are held in Appendix B until the Midwest ISO review process is completed. All projects in Appendix B have documented system needs associated with them.

Appendix C

Appendix C may contain projects which are still in the early stages of Transmission Owners planning process or are have just entered the MTEP study process and have not be reviewed for need or effectiveness. Appendix C may contain some long-term conceptual projects. There are some long-term conceptual projects in Appendix C, which will require significant amounts of planning before they are ready to go through the MTEP process to be moved into Appendix B or Appendix A. Appendix C may contain project alternatives to the best alternative presently in Appendix B. Therefore, a project could move from B back to C if a better alternative is determined, yet the TO is not ready to withdraw the previous best alternative. Appendix C projects are not included in MTEP07 initial powerflow models used to perform baseline reliability studies due to high degree of uncertainty surrounding project from Midwest ISO's perspective. Appendix C projects are not eligible for regional cost sharing.

Project Database Versus Appendices A, B, and C

The Midwest ISO Project Reporting Guidelines which were approved by Planning Subcommittee on August 8, 2006 require that the following system changes be reported to Midwest ISO:

1. All projects that represent a system topology change (new circuit, tapping an existing circuit, removal of circuit in model, or retirement). Need to know new distribution sub taps.
2. All new circuit breaker additions (upgrades of existing described below)
3. All upgraded circuit breakers (changed continuous current carrying or interrupting capability)
4. All projects that change the electrical characteristics of a circuit (e.g. shunt or series inductors or capacitors, reconductoring, replace switches, change current transformers, replace wavetraps)
5. Like-for-like replacements with direct costs of $1 million or higher

6. Projects that change a circuit rating
7. Generator interconnection projects with signed Interconnection Agreements (provided by Midwest ISO Interconnection Planning)

This information is required for the MTEP process and model building process. However, some data which is reported for model building does not need to be reviewed or approved in MTEP process. For example, a Transmission Owners has 69 kV system which is not under Midwest ISO functional control, however, it is important for Midwest ISO to have this information to accurately develop powerflow models. The Midwest ISO Project Database contains both MTEP and model building information and is queried to extract project information which is applicable for MTEP. In general, projects with voltages under 100 kV are not included in MTEP Appendix A, B, and C unless under Midwest ISO functional control. For example, a 138/69 kV transformer or 69 kV switched capacitor required to support the transmission system which is not under Midwest ISO functional control would not be included in Appendix A, B or C.

Planning Statuses in Project Database reflect the Transmission Owners planning process status, not Midwest ISO's review process. Therefore, a TO could submit a project for which they have completed planning, yet it would still go into Appendix C until Midwest ISO staff reviews the project. Appendix A, B and C reflect the Midwest ISO review process.

MTEP07 Appendices A and B

The results of the MTEP07 Baseline Reliability analyses and Midwest ISO service related studies have determined that the projects currently identified in the Appendix A (recommended by Midwest ISO staff for approval by Midwest ISO Board of Directors) and Appendix B (projects not recommended for approval at this time) of MTEP 07 are sufficient to maintain system reliability and provide for requested service. The results of the MTEP reliability analyses are described in Section 6 of this report.

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3. Midwest ISO System Information

3.1. Midwest ISO System Overview

The Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit, member-based organization committed to being the leader in electricity markets by providing our customers with valued service, reliable, cost effective systems and operations, dependable and transparent prices, open access to markets, and planning for long-term efficiency.

Midwest ISO has members in 15 states and one Canadian province. Our members' systems cover 920,000 square miles with 93,600 miles of transmission operated at 500kV, 345kV, 230kV, 161kV, 138kV, 120kV, 115kV, and 69kV.

3.2. Load and Generation Trends

3.2.1. Load Forecast

The Midwest ISO does not currently prepare a long-term load forecast. Load projections are reported by Network Customers under Module E of the tariff, and are represented in planning models developed collaboratively between the Midwest ISO and our transmission-owning members. Members also provide load forecasts through the NERC regional reporting processes. Resource adequacy is evaluated under the tariff by requiring load serving entities to report their Network Resources that will be used to meet state and Regional Reliability Organization (RRO) resource adequacy guidelines. Historically, reported load forecasts have been accurate as each member has expert knowledge of their individual loads.

Table 3.2-1 displays the reported summer peak net internal demand growth from 2006. The 2006 demand values for the Central Planning Region and the Midwest ISO have been adjusted to reflect the departure of Louisville Gas & Electric from the Midwest Market. Net internal demand is defined as internal demand less demand response programs; interruptible load (IL) and direct control load management (DCLM). From 2006, the Midwest Market experienced a load growth of 1.84%. In 2007, 769 MW more demand response was reported than in 2006, which lowered the growth rate by an additional 0.7%.

	2006 Net Internal Demand	2007 Net Internal Demand	Load Growth: 2006 → 2007
East	37,732 MW	38,487 MW	2.00%
Central	38,540 MW*	39,028 MW	1.27%
West	30,858 MW	31,585 MW	2.36%
Midwest ISO	***107,130 MW****	***109,099 MW***	**1.84%**

Table 3.2-1: Load Growth from 2006 **Excludes LG&E*

Load Serving Entities (LSE) in Michigan reported a slightly negative load growth from 2006; however, the East Planning Region still reported a 2% growth rate because Ohio reported a demand growth of 5%. The Central Planning Region's growth rate remained relatively the same as reported from 2005 to 2006. The West Planning Region experienced the highest growth rate while having a 1,043 MW increase in reported demand response programs; this may be largely due to a change in reporting procedure. The majority of these programs were located in Minnesota.

Figure 3.2-1 displays the net internal demand levels for the 2007 planning year. Contingency Reserves (CR) are modeled as a load addition to represent that they cannot be used unless load curtailment is imminent. The Contingency Reserve Sharing Group (CRSG), which consists of both Midwest Market members and non-members, has a reserve requirement of 2,250 MW. 1,662 MW of the CRSG reserve requirement belong to Midwest Market members and is modeled in Figures 3.2-1 and 3.2-2.

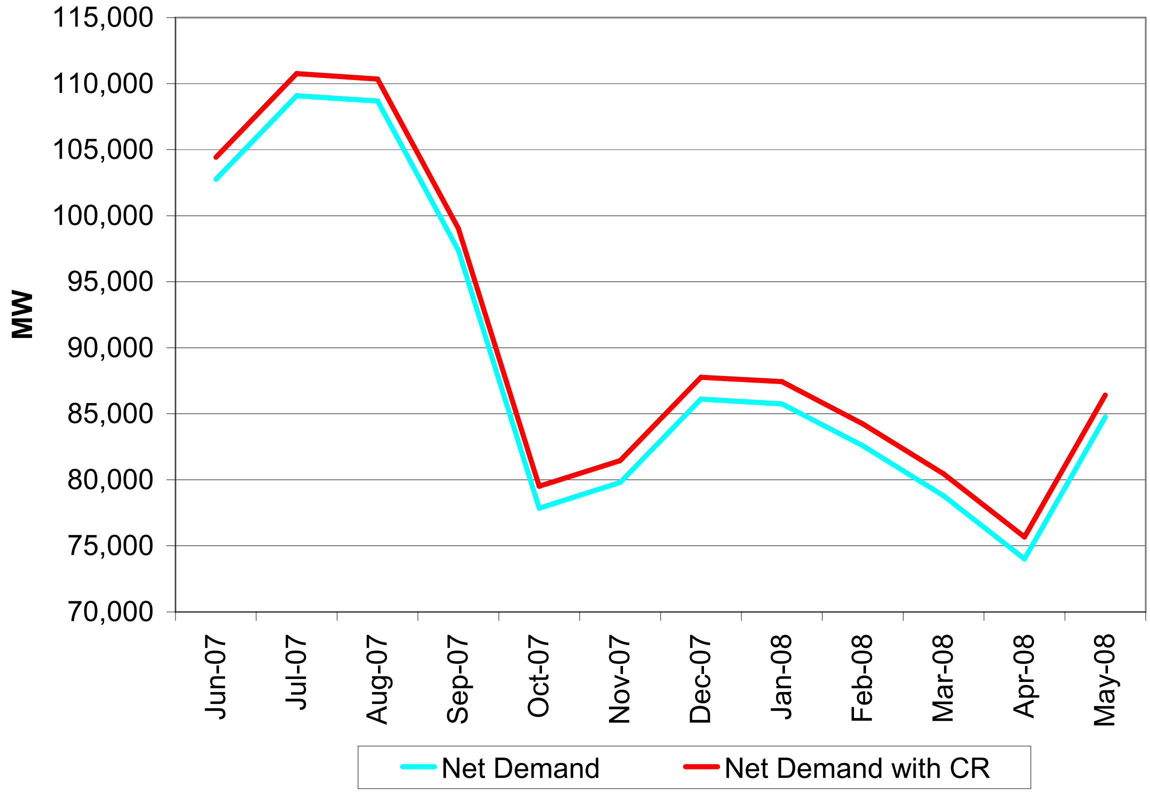


Figure 3.2-1: 2007 Planning Year Forecasted Demand

Figure 3.2-2 and Table 3.2-2 display the summer peak demand forecast for the next ten years. The summation of Midwest Market Participants' net internal demand forecasts has an average annual growth rate of 1.5%. This is slightly below the historical average growth rate which has been between 1.8% and 1.9%. This below average reported rate could be attributed to difficultly in forecasting future load for Illinois Load Auction members.

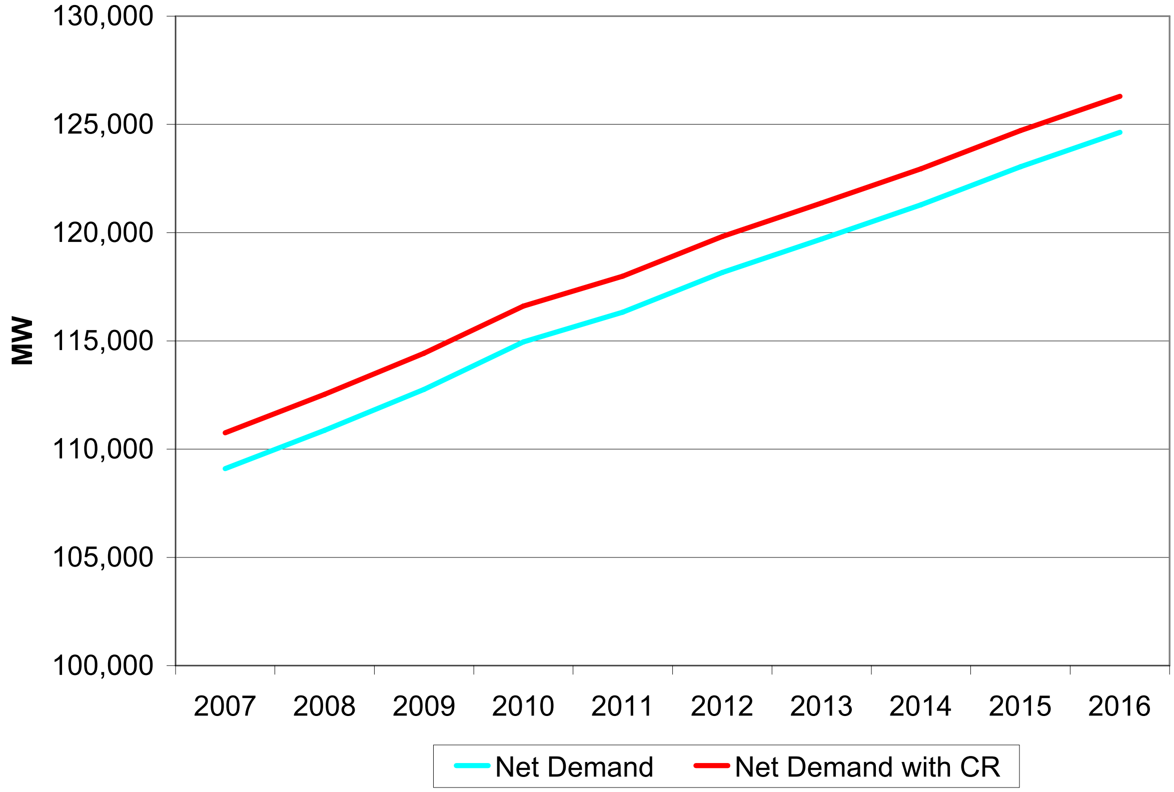


Figure 3.2-2: Ten-Year Forecasted Summer Peak Demand

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
With CR	110,761	112,531	114,426	116,613	117,990	119,825	121,366	122,949	124,711	126,294
Without CR	109,099	110,869	112,764	114,951	116,328	118,163	119,704	121,287	123,049	124,632

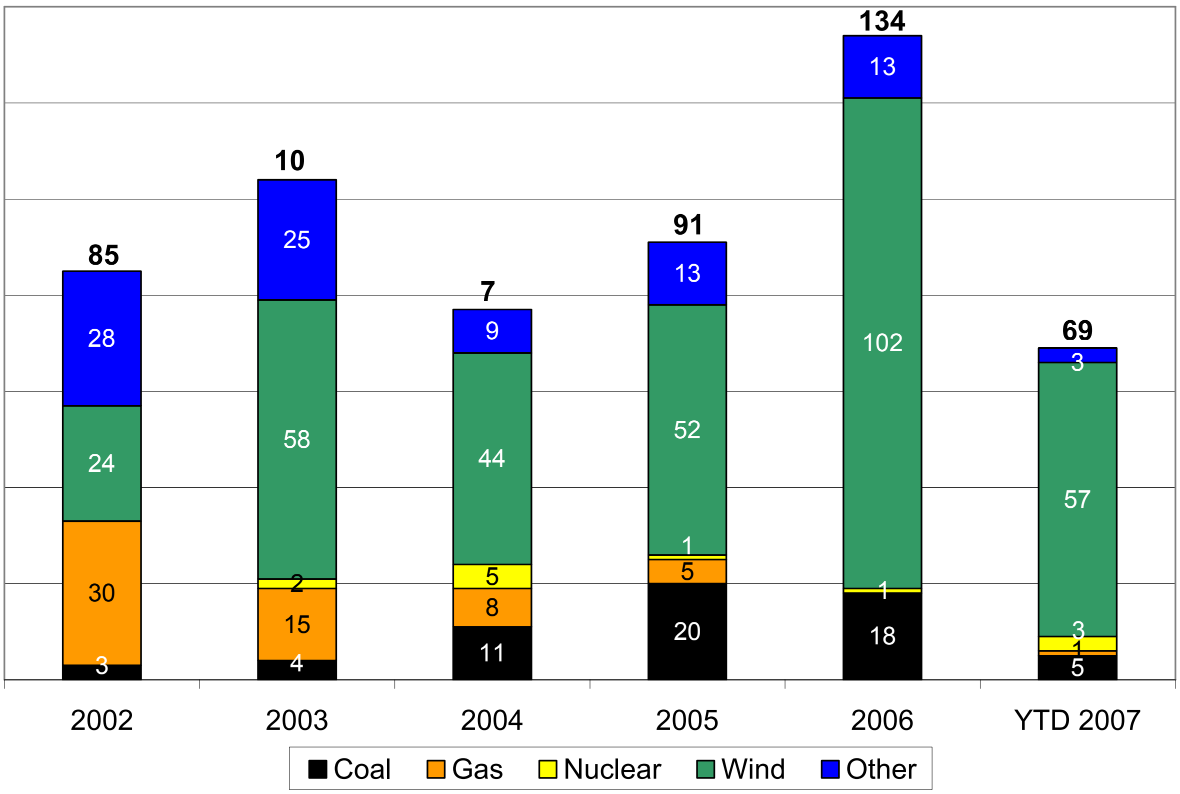
Values in MW

Table 3.2-2: Ten-Year Forecasted Summer Peak Demand

Recently, there has been an increased awareness in demand side management and conservation programs. Many utilities have discussed plans to initiate new programs or expand their existing; however, the reported forecasts don't indicate an increase in demand side management and thus the aforementioned net internal demands use only the current penetrations. Across the Midwest Market footprint 4,000 MW of demand side management is reported through 2016.

3.2.2. Midwest ISO Generator Interconnection Queue

During the past five years the number of active generator interconnection queue entries has continued to rise. There has also been a considerable shift in the types of requests. Driven by the Renewable Portfolio Standards, there has been a vast increase in the number of active wind projects in the queue. From 2005 to 2006, the number of queued wind projects doubled. With more states considering renewable energy mandates the number of queued wind projects is expected to continue to increase. Figure 3.2-3 details the number and types of generator interconnection queue requests from 2002 to May 1, 2007.



YTD: Requests received as of May 1, 2007

Figure 3.2-3: Number of Generator Interconnection Queue Requests

Figure 3.2-4 displays the location of active queue projects. Numerous relatively large generation projects are located in remote areas a great distance from the load centers, requiring significant transmission upgrades. The bulk of the active queue projects are concentrated in the southwestern portion of Minnesota, eastern South and North Dakota, and northern Iowa where wind is most prevalent. Several large non-wind projects are located in northern Minnesota, central Michigan, and southern Illinois. Note that Figure 3.2-4 below shows both Midwest ISO interconnection requests (in black) and interconnection requests to non-Midwest ISO transmission system (in red). The latter are called coordinated requests. Coordinated requests are represented in Midwest ISO queue and included in Midwest ISO interconnection studies, which honor the queue priority of these requests.

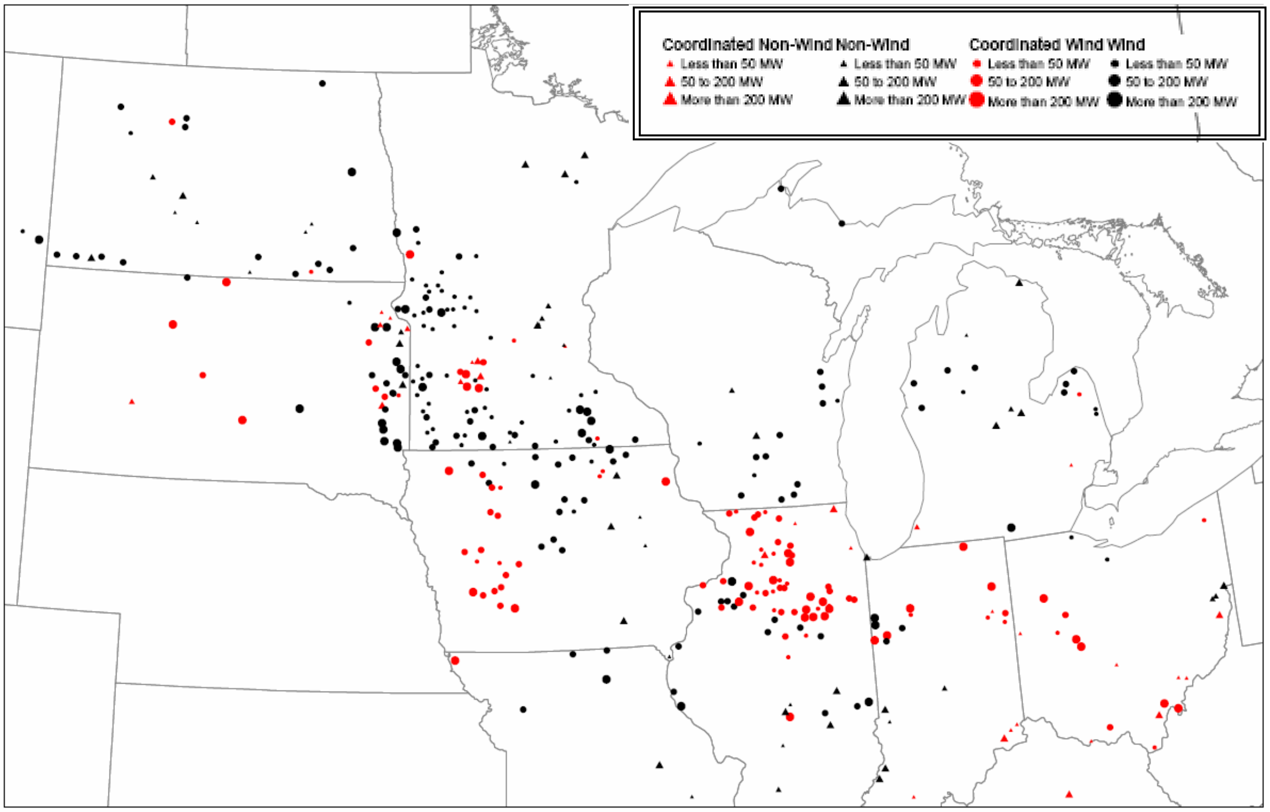


Figure 3.2-4: Generator Interconnection Queue Map

Currently there is 42,414 MW of active Midwest ISO projects in the Generator Interconnections Queue. Of the 229 active projects, there are 33 projects with a signed interconnection agreement (IA) and an expected in-service date prior to 2016. These projects are expected to add 7,945 MW of additional capacity to the Midwest Market footprint. The expected capacity additions are dominated by 4,511 MW of coal projects. Gas fueled combined cycle projects amount to 1,805 MW and wind projects total 1,008 MW. In the next ten years there are also 836 MW of known retirements. Many of these retirements are existing coal-powered plants that are being converted into gas-fired combined cycle units. Figures 3.2-5 and 3.2-6 detail the capacity additions and retirements over the next ten years.

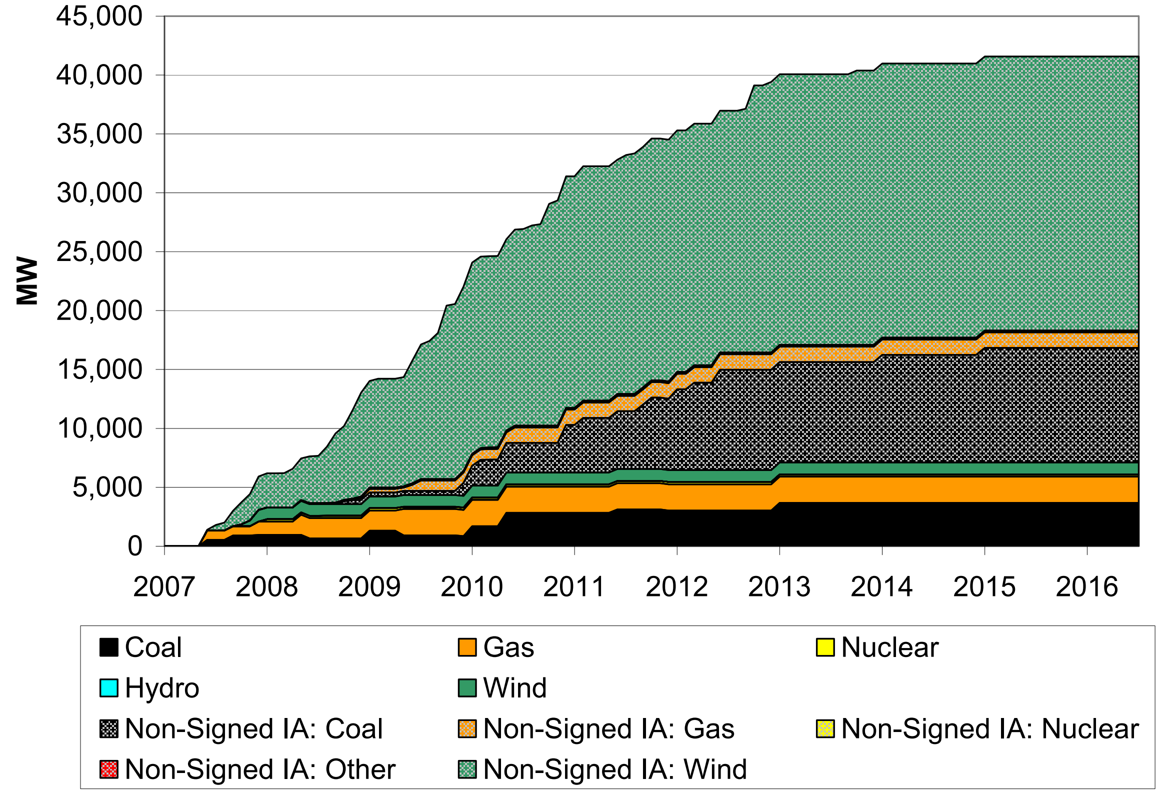


Figure 3.2-5 Generation Capacity of Active Queue Entries and Known Retirements

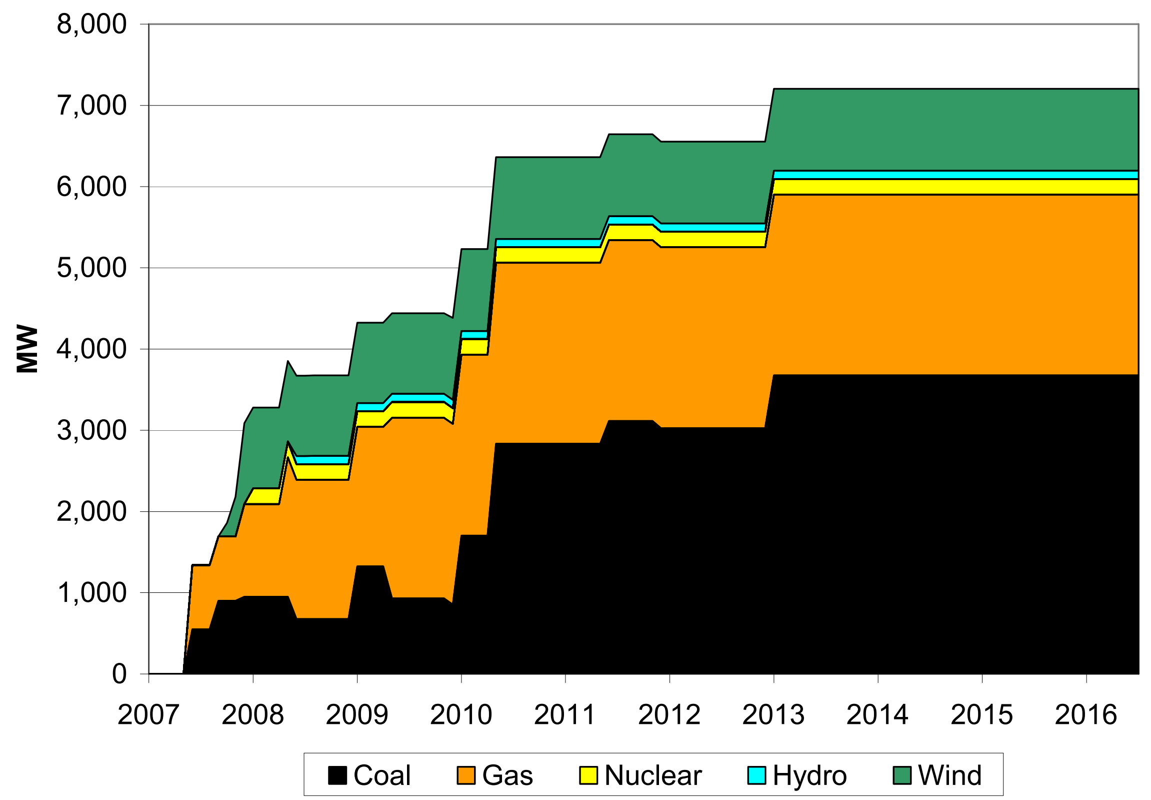


Figure 3.2-6: Capacity of Signed IA Queue Entries and Known Retirements by Fuel Type

Figures 3.2-7 and 3.2-8 break down both the current 2007 generation capacity and the forecasted 2016 capacity by fuel type. Currently there is 127,210 MW of capacity that physically resides within the Midwest Market footprint and can be monitored by the Midwest Market's meters. This value does not account for seasonal derations.

The forecasted capacity is attained by adding generation in the queue with a signed IA, and by removing units with a retirement date prior to 2016. In both cases the predominant fuel type is coal, accounting for approximately 50% of the total capacity. The largest change during the ten-year span is in the amount of wind generated capacity.

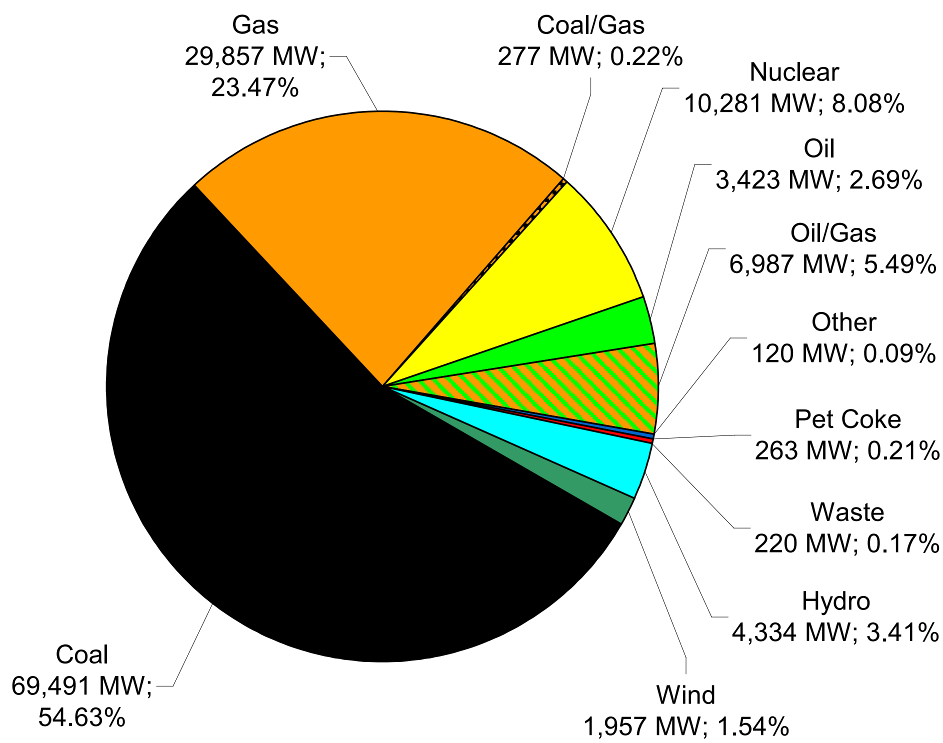


Figure 3.2-7: 2007 Capacity by Fuel Type

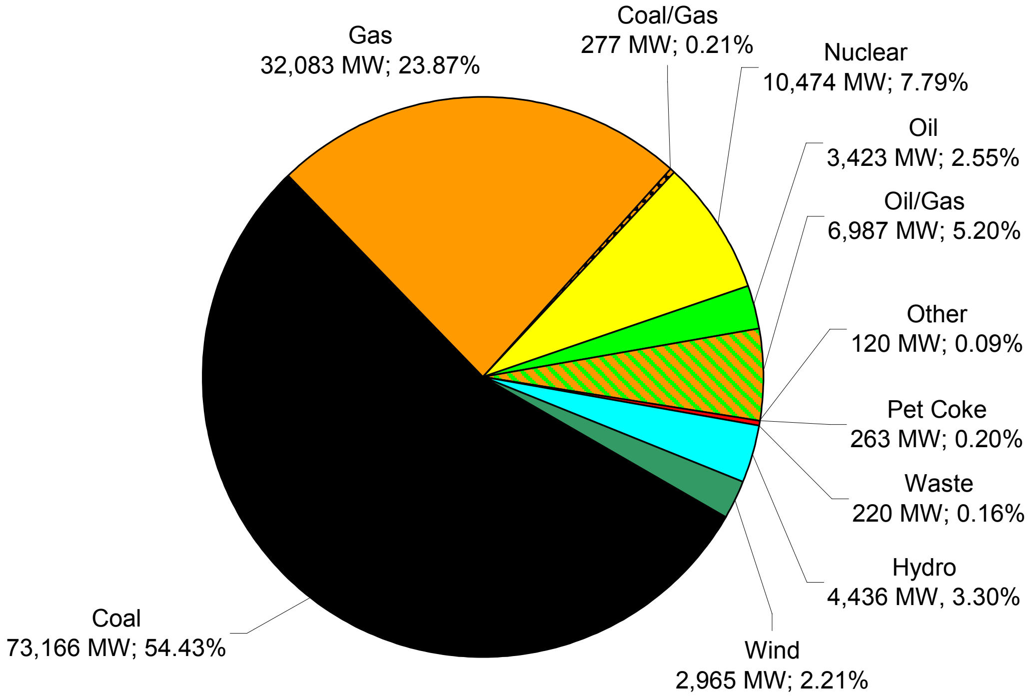


Figure 3.2-8: 2016 Projected Capacity by Fuel Type

3.2.3. Reserve Margin Forecast

The Midwest ISO is expected to have a reserve margin that ranges from 21% in 2008 to 5% during the 2016 summer peak. Reserve margins were calculated using two alternative definitions, the NERC Reserve Margin and the Midwest ISO Effective Margin.

The NERC Construct Reserve Margin (NRM) is based on the formula defined by the Energy Information Administration's 411 template. Demand side management is represented as a load reduction and assumed to be 100% available and at the reported level. If only half of the demand side management programs are available on peak the reserve margin lowers by an additional 3.5%. The capacity used in the reserve margin calculations is the same as discussed in the previous section with the addition of known behind-the-meter resources. No distinction is made between capacity committed to the Midwest Market and capacity committed outside of the footprint for this calculation. Applying a seasonal operating deration of 6,000 MW, as experienced during the 2006 summer, lowers reserve margins by 5%.

Figure 3.2-9 details the demand and capacity used for the NERC Construct Reserve Margin calculations.

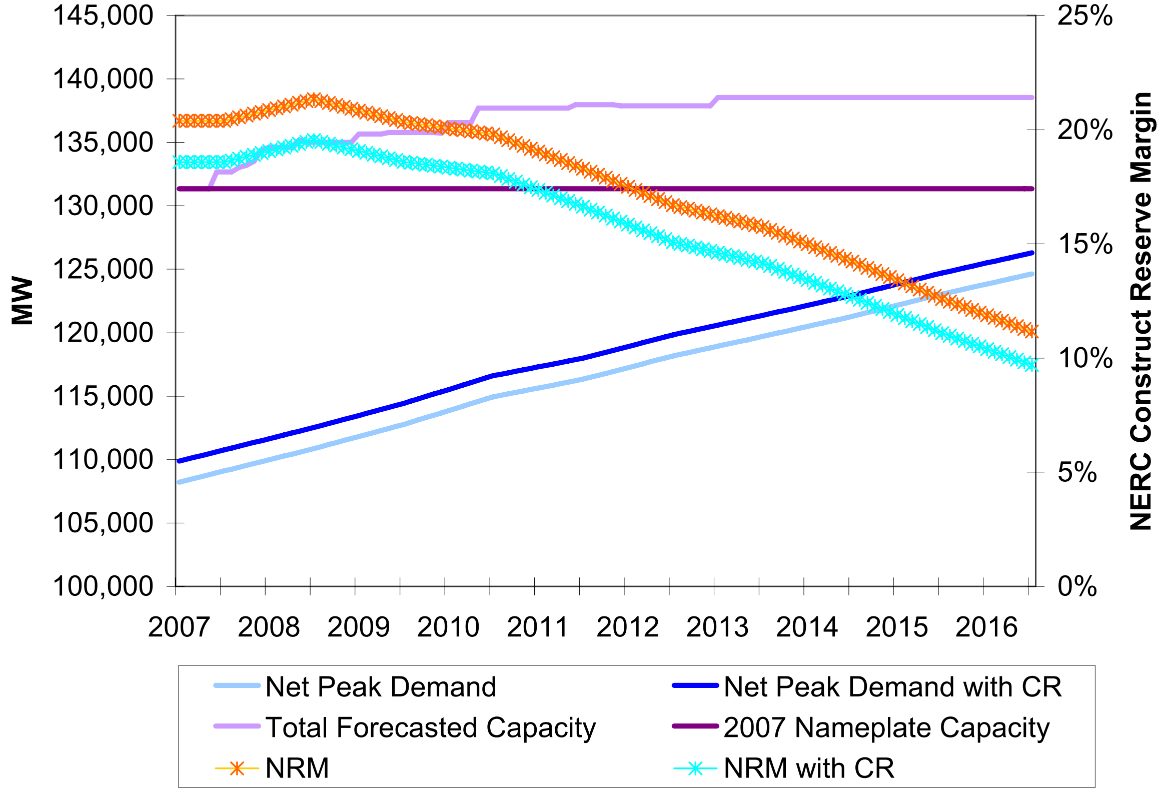


Figure 3.2-9: NERC Reserve Margin Ten-Year Load and Capacity Forecast

Figure 3.2-10 displays the ten-year summer peak reserve margin forecast with and without the 1,662 MW of contingency reserves included. Table 3.2-3 details the forecasted summer peak reserve margins.

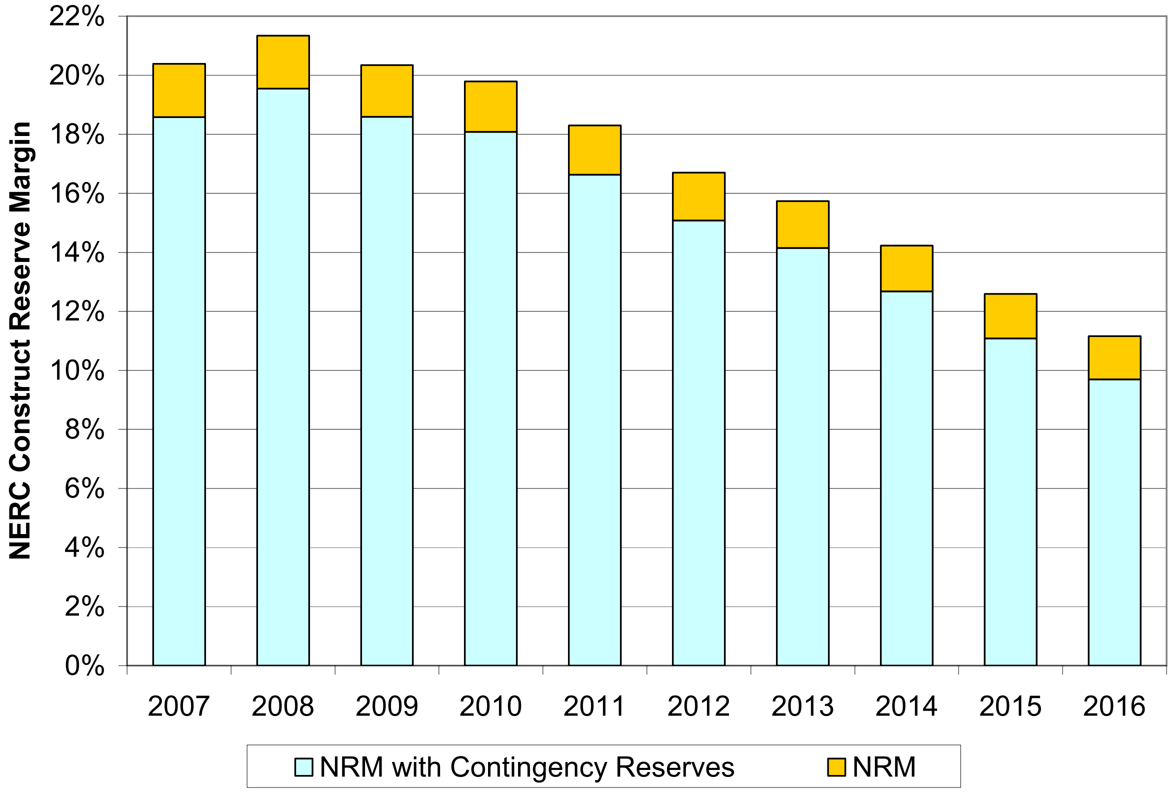


Figure 3.2-10: NERC Reserve Margin Ten-Year Summer Reserve Margin Forecast

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
With CR	20.4%	21.3%	20.3%	19.8%	18.3%	16.7%	15.7%	14.2%	12.6%	11.2%
Without CR	18.6%	19.5%	18.6%	18.1%	16.6%	15.1%	14.2%	12.7%	11.1%	9.7%

Table 3.2-3: NERC Reserve Margin Ten-Year Summer Reserve Margin Forecast

The Midwest ISO Effective Margin (MEM) is a more conservative view on reserve margin with a formula based on historical operating data. Demand side management is represented as a capacity addition at the reported level. By representing demand side resources as capacity it gives the opportunity to apply outage rates to model the possibility that the resources may not be available when called upon. The capacity used in the Midwest ISO Effective Margin calculation has a historical summer deration applied to it. Only units that regularly offer into the Midwest Market are included. 4,126 MW of known behind-the-meter resources are also included as in the NRM.

Figure 3.2-11 details the demand and capacity used for the Midwest ISO Effective Margin calculations.

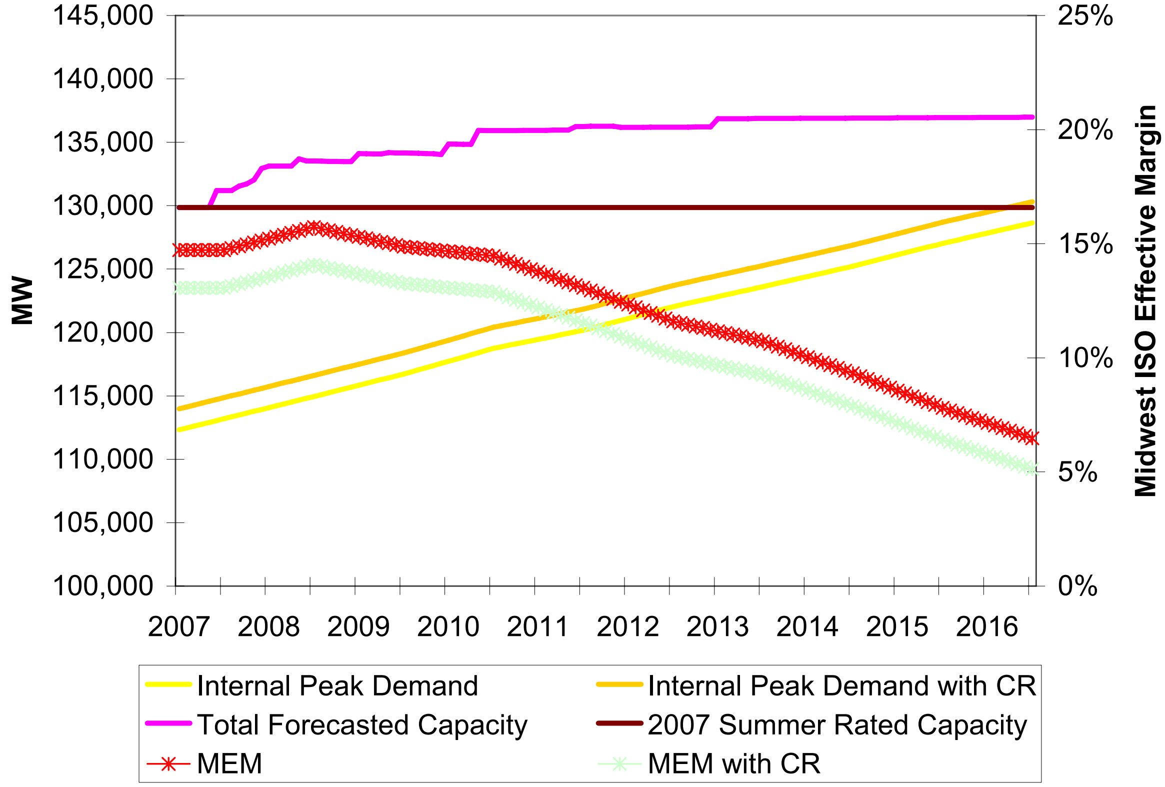


Figure 3.2-11: Midwest ISO Effective Margin Ten-Year Load and Capacity Forecast

Figure 3.2-12 displays the ten-year summer peak Midwest ISO Effective Margin forecast with and without the 1,662 MW of contingency reserves included. Table 3.2-4 details the forecasted summer peak reserve margins.

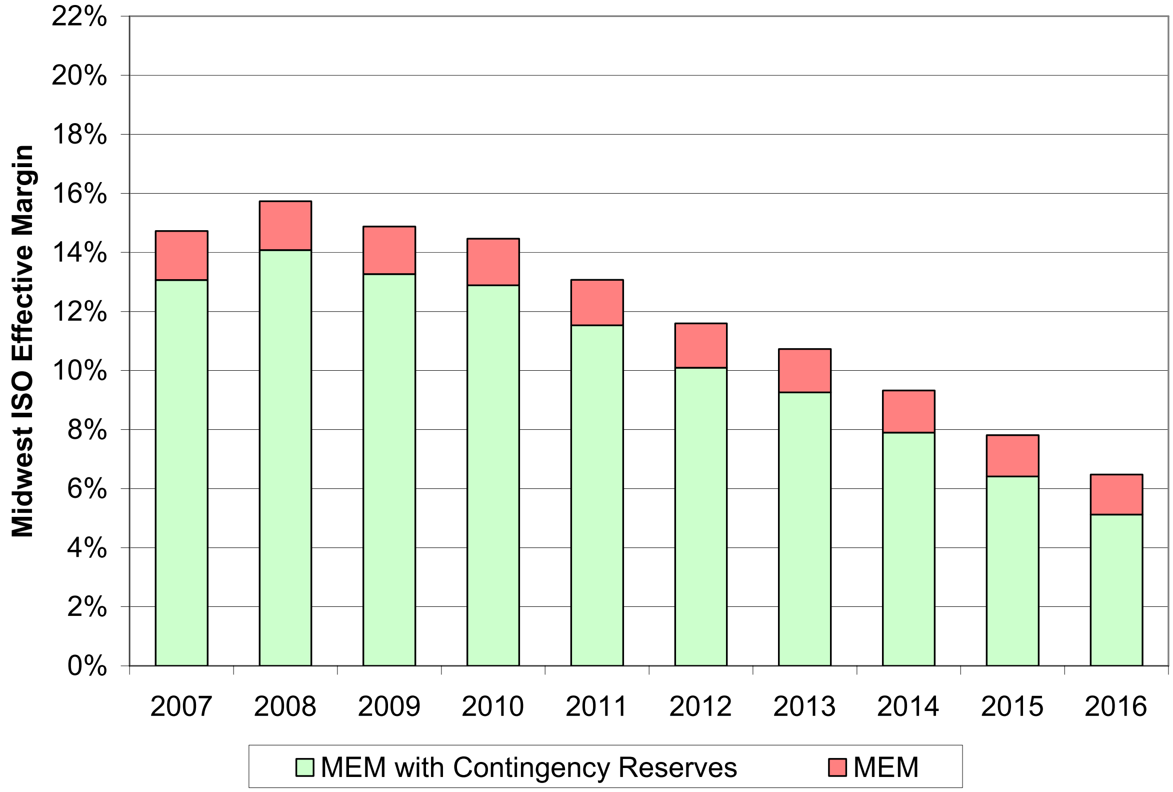


Figure 3.2-12: Midwest ISO Effective Margin Ten-Year Summer Reserve Margin Forecast

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
With CR	14.7%	15.7%	14.9%	14.5%	13.1%	11.6%	10.7%	9.3%	7.8%	6.5%
Without CR	13.1%	14.1%	13.3%	12.9%	11.5%	10.1%	9.3%	7.9%	6.4%	5.1%

Table 3.2-4: Midwest ISO Effective Margin Ten-Year Summer Reserve Margin Forecast

Given the current 2007 capacity and without including demand response programs or behind-the-meter generation, a deficient NERC Reserve Margin and Midwest ISO Effective Margin of -1.1% and -5.5%, respectively, is expected for 2016. If the 2016 forecasted demand is reduced by executing the 4,013 MW of demand response programs reported for 2016, the NERC Reserve Margin rises to 2.1%. If instead, demand response is represented as a capacity addition the Midwest ISO Effective Margin rises to -2.2%. With the addition of 7,207 MW of queued capacity with a signed IA and known 4,126 MW of behind-the-meter generation, the NERC Reserve Margin rises to 11.2% and the Midwest ISO Effective Margin to 6.5%. If the 1.9% historical average load growth rate is applied to the 2007 peak load and the same demand side programs are included the NERC Reserve Margin drops to 3.9% and the Midwest ISO Effective Margin to 2.1%. As evident in these calculations changes in demand response levels, behind-the-meter generation levels, seasonal derations on generating units, footprint definition, and load growth rates have a significant impact on the reserve margin.

3.3. Historical Operating Data

In a broad sense Congestion has tended to increase in the Midwest RA footprint since the year 2001. Congestion is an ongoing dynamic experience from year to year or even month to month. The historical analysis is just one of several inputs utilized in determining if particular expansion to reduce congestion is warranted. Table 3.3-1 illustrates both increased utilization of congested flowgates and also shows the number of flowgates that were congested annually. Some flowgates that were used in the past are not utilized going forward or become inactive for a period of time. Also, new flowgates or flowgates previously not used since January 1, 2007 become active. For example of the 829 flowgates used in the April 2006 to April 2007 period only 262 had a previous history of congestion since January 1, 2001. This transient aspect can be attributed to changing transmission and generation infrastructure, and unique maintenance or weather driven effects within a given period of time. While the number of flowgates utilized in each year continues to rise the overall average hours that flowgates are congested is declining as shown by the right hand column in Table 3.3-1.

**Table 3.3-1 Number of Flowgates Utilized
And Annual FG-Hours Since January 1, 2001**

	Number of Flowgates Utilized			
Time Period	Utilized In The Period	Cumulative Utilized Since January 2001	Congestion FG-Hours In Period	Average Hours/FG Utilized In The Period
April 2006 - April 2007	829	1,672	20,329	25
April 2005 - April 2006	749	1,105	27,842	37
April 2004 - April 2005	200	358	11,050	55
April 2003 - April 2004	174	316	11,094	64
April 2002 - April 2003	89	116	10,172	114
January 2001-April 2002	64	64	6,432	101

The column second from the right in Table 3.3.1 shows that in the pre-Midwest ISO market time frame, the annual (April to April) congestion was fairly constant at between 10,000 and 11,000 FG-Hours per year from April 2002 to April 2005. Both the number of utilized flowgates and the FG-Hours increased in the post Midwest ISO market time frame. While, the number of flowgates utilized increased from 749 in the 1st Market year to 829 in the 2nd Market year; the 2nd Market year saw a reduction to 20,329 FG-Hours, down from the 1st Market year peak of 27,842 FG-Hours. The increase annual FG-Hour metric after April 1, 2005 speaks to the point that the LMP market more fully utilizes and effectively optimizes use of the available transmission system up to reliability limits.

As one moves forward in expansion planning, careful consideration will be necessary to identify transmission investments that may address congestion, and at the same time avoid transmission investment to mitigate congestion when the benefit to do so would be short lived. Most of the congestion observed in the Midwest ISO has some associated reliability based projects that will mitigate the hours of congestion observed historically. A few congested areas have no current associated mitigating project driven from reliability analysis of the system. Beyond reliability needs, plans are for study in MTEP08 to investigate the cost effectiveness of future projects to reduce congestion.

Transmission system constraints that limit the availability of transmission service reservations or that limit the flow of scheduled transmission service reservations; generally represent limitations to the commercial use of the system, rather than limitations to the reliability of the system. This review will focus on real-time operations in the two year period since April 2005 where congestion has been managed through a combination of Transmission Loading Relief (TLR) and by binding elements in the Midwest ISO market. Midwest ISO implemented a centrally controlled security constrained economic dispatch as a part of the LMP based market. This dispatch is now the primary process for controlling security constraints on an operational basis. The central dispatch process is directed at economically dispatching the system while honoring constraints and avoiding security violations.

To have an element or flowgate (FG) “bound” means that a defined flow limit has been set (i.e. a bound) for the element within the Midwest ISO market security constrained economic dispatch program. The market will then be redispatched at some resulting higher cost level in order to maintain the flow within the set limit. The TLR (through curtailment of scheduled transactions) and market re-dispatch (via binding elements) are available for implementation when system conditions are other than planned. Both processes are targeted to prevent system security violations if a contingency were to occur. Commercial limitations to use of the transmission system give rise however to congestion costs that may or may not exceed the costs of relieving the constraints. Much of the congestion realized simply reflects proper management of the system within reliability limits, and is not reflective of other eminent problems or expansion needs. Given adequate generation reserves, the transmission system becomes the “ultimate sentinel” for reliability. Any subsequently realized transmission congestion has two faces. When transmission limits are reached and there are adequate generation resources to shift supply the reliability risk is very low. This is the situation for a great majority of the time. Alternatively, when a transmission limit is reached and generation resources are fully utilized, the situation presents concern, because there could be limited choices for an alternative dispatch. The following discussion provides information about constraints that have been most frequently involved in limiting transactions via TLR or have been bound in the Midwest ISO market dispatch. Both TLR and Midwest ISO market redispatch measures are used to maintain system reliability.

The primary value in summarizing the congestion history is that this provides one metric of system performance. This summary does not include tracking the individual impacts among flowgates or of new flowgates being introduced or other dynamics as the generation and transmission system itself changes over time. While no particular attempt has been made in MTEP to dissect specific historical data or merge commonly impacted flowgates, this summary (particularly the individual flowgate charts in Appendix E1) provides a basis for such detailed investigations. This type of information is commonly utilized along with further local knowledge incorporated into more detailed discussions for specific projects’ needs or in addressing stakeholder questions about the transmission system.

It should be recognized that the historical congestion realized by TLR or binding in the Midwest ISO market has predominantly functioned as a security operating mechanism where expansion solutions were not necessary. Therefore, historically predominant congestion locations may or may not be associated with need for transmission facility expansion.

To characterizing this large amount of history, past MTEP report's congestion summaries focused heavily on average statistics as far back as January 1, 2001. In this MTEP07 particular emphasis has been placed on the more recent timeframe for the first 24 months of the Midwest ISO market operations (April 1, 2005 through March 31, 2007). Aggregated or averaged summaries can be misleading in that they do not reflect modifications to the network over time or the impact of rare patterns due to weather or other unusual generation availability patterns. Unusual events can cause a flowgate to be congested for a relatively high number of hours over a short time but not represent an issue going forward. Therefore, the reader is urged to reflect upon the detailed monthly congestion patterns for the more active flowgates as illustrated in Appendix E1. It is intended that the charts in Appendix E1 will provide a basis for further insight. On occasions Midwest ISO and its members have provided more intensive analysis and explanations for specific flowgates of interest, and will continue to contribute to such forums beyond an MTEP report.

3.3.1. History of Congestion

This historical review is based on including a flowgate (FG) as a Midwest ISO flowgate if the facility is under the Midwest ISO Reliability Authority (RA). For example, this includes flowgates owned by Midwest ISO Transmission Owners (TOs), and includes flowgates of non-member systems in the MAPP group of transmission companies that have their RA functions contracted to Midwest ISO. Prior to MTEP06 congestion was tracked by analyzing TLR records only. Since the start of the Midwest ISO market on April 1, 2005; congested transmission elements may have contributed to the congestion component of the Real Time (RT) LMP. The term "bound" is used to refer to an element or flowgate that is requiring out-of-order dispatch of generation resulting in a marginal congestion component (MCC) within the calculated LMP price. The following discussion will relate to TLR activity, or to bound activity, and sometimes to both TLR and bound. Figure 3.3-1 illustrates the sum of monthly flowgate hours of congestion and the relative method of managing congestion since from January 2001 through March 2007. Note the exclusive use of TLR for congestion management in the pre-Midwest ISO market period versus the post Midwest ISO market period when both TLR and bound constraints in the LMP central dispatch were utilized. The legend term "Bound Only" refers to flowgate congested hours that were managed through redispatch by adjusting LMP prices. The term "TLR Only" refers to the flowgate congested hours that were exclusively managed by the NERC TLR process only. The legend term "Bound and TLR" refers to flowgate congested hours in which the TLR and Bound redispatch were utilized concurrently.

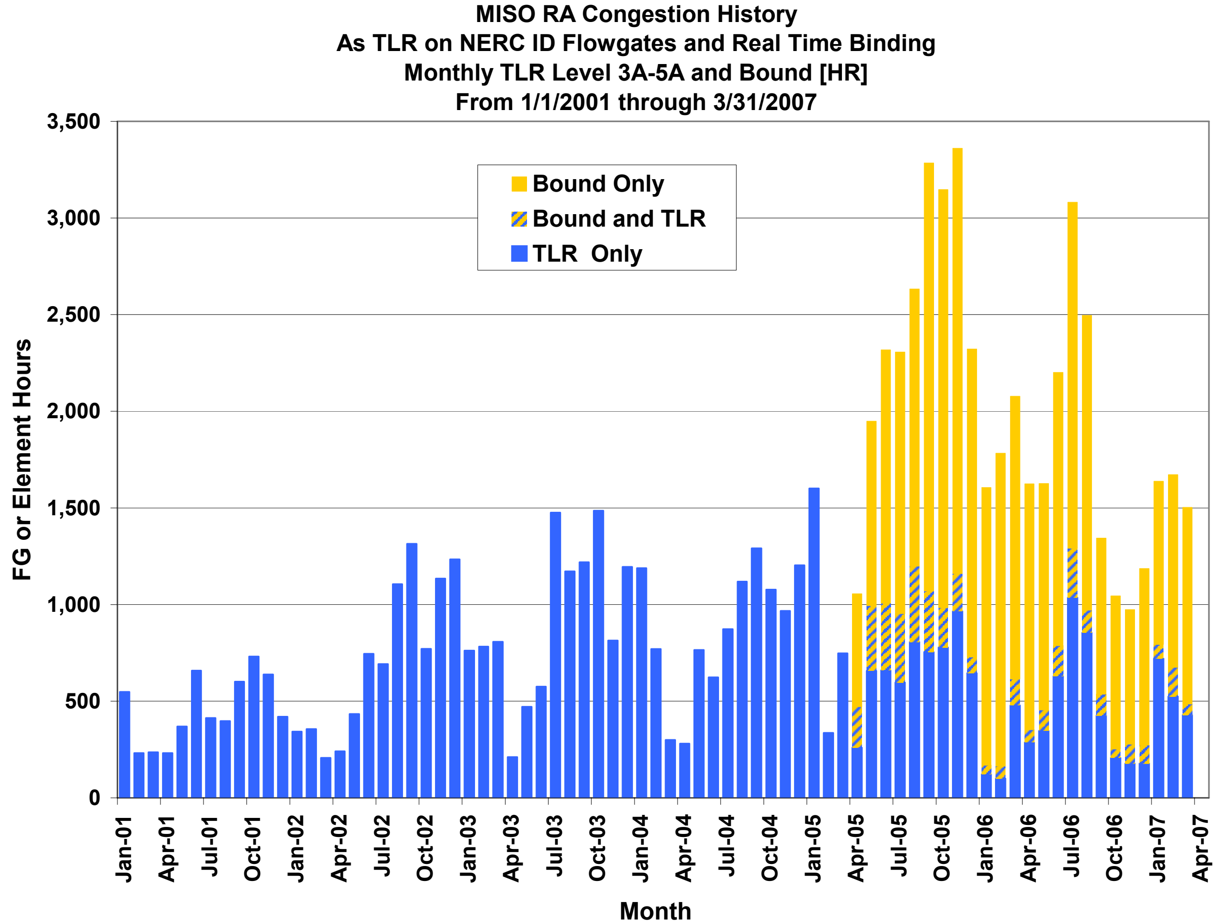


Figure 3.3-1 Overview History of Midwest ISO Congestion and Method

Similarly, Figure 3.3-2 shows the itemization by TLR Level for hours that were affected exclusively or in part by TLR. The “Bound Only” portions in Figure 3.3-2 is the same as the “Bound Only” portions plotted in Figure 3.3-1 Relative to Figures 3.3 -1 and 3.3-2, the first six months of the Midwest ISO market (April 1, 2005 through September 30, 2005) had higher levels of congestion activity. Market analysis has shown that the predominant factor was a lag in business activity between the Midwest ISO market footprint and the bordering non-Midwest ISO market participant areas. In effect the two adjoining groups tended to conduct business as if they were segregated systems. After those first six months, increased familiarity with new systems and business practices that permit transactions into and out of the Midwest ISO market brought on a reduction in the congestion activity.

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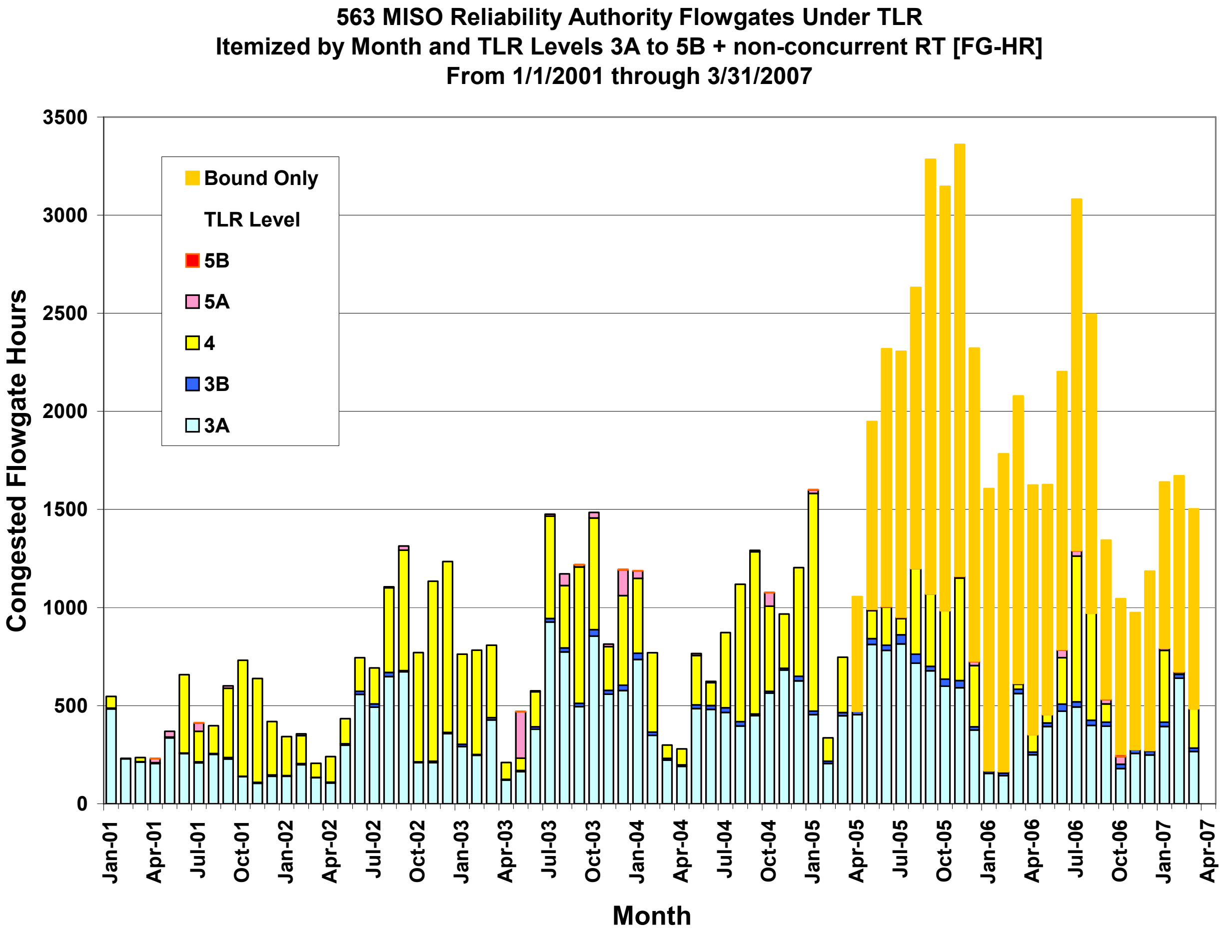

Figure 3.3-2 Overview History with TLR Affected Hours Itemized by TLR Level

Nine levels of TLR are listed below. Figures and other summaries that reference TLR in this report are inclusive of the TLR levels ranging from curtailing transactions (Level 3a) to taking Emergency action (Level 6). This range of TLR is consistent with the RT implementation of bound elements. Both this TLR range and the binding elements the Real Time (RT) Midwest ISO market, represent actions upon actually observing flows on the system. Whereas lower levels of TLR and Day Ahead (DA) Midwest ISO market operations are reflective with actions in anticipation of high flows. The process of Transmission Service Requests on the OASIS is also an anticipation type of process that is implemented before high flows are observed on the system. Most of the flow reductions obtained through TLR are achieved in the range of levels from 3A to 4, very little flow relief is achieved by use of level 5 schedule reductions.

Level 0: Level 0 refers to normal operation. This accounts for transactions that were defaulted to zero MW due to improper Tag information.

Level 1: Notify Reliability Coordinators of potential operating security limit violations

Level 2: Hold interchange transactions at current levels to prevent operating security limit violations

Level 3a: Curtail transactions using Non-firm Point-to-Point transmission service to allow transactions using higher priority Point-to-Point transmission service

Level 3b: Curtail transactions using Non-firm Point-to-Point transmission service to mitigate operating security limit violations

Level 4: Reconfigure transmission system to allow transactions using Firm Point-to-Point transmission service to continue

Level 5a: Curtail transactions (pro rata) using Firm Point-to-Point Transmission Service to allow new transactions using Firm Point-to-Point Transmission Service to begin (pro rata)

Level 5b: Curtail transactions using Firm Point-to-Point transmission service to mitigate operating security limit violations

Level 6: Emergency action.

Table 3.3-2 lists 52 flowgates that on the average were congested more than 1% of the time in the post-Midwest ISO market period (over 175 hours in the two year period). If more that one flowgate has the same total hours they share a Ranked position. Table 3.3-2 also shows the average annual hours of congestion for the pre-Midwest ISO market period, the 1st Market year, and the 2nd Market year. The yellow high lighted rows indicate ten flowgates that realized increased congestion in the 2nd Market year, and the top 10 of those high lighted flowgate are addressed in later discussion related to Figure 3.3-5. Figure 3.3-3 is a chart of the 52 flowgates that itemizes the total exclusive hours bound and hours at each TLR Level.

Table 3.3-2 The 52 Post Market Flowgates That on the Average were Congested More Than 1% of the Time (see Figure 3.3-3 for long-term Bound versus TLR breakdown of all 1,672 Congested FGs)

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Pre Market Congestion FG-Hr/YR Jan 01 to Apr 05	1st Year Market Congestion FG-Hr/YR Apr 05 to Apr 06	2nd Year Market Congestion FG-Hr/YR Apr 06 to Apr 07	BA	MTEP Map Grid
1, 100	Kammer 765/500 kV XFMR (flo) Belmont - Harrison 500 kV	0	1733	338	PJM	Q9
1, 2353	Black Oak - Bedington 500 kV (flo) Pruntytown - Mt. Storm 500 kV	0	914	1,157	PJM	Q10
3, 3006	Eau Claire - Arpin 345 kV	145	1529	245	WPS	J6
4, 2245	Blue Lick - Bullitt Co. 161 kV (flo) Baker - Broadford 765 kV	48	1699	44	LGEE	N11
5, 2872	Frankfort East - Tyrone 138 kV (flo) Ghent - West Lexington 345 kV	49	1151	132	LGEE	M11
6, 6004	Minnesota Wisconsin Stability Interface (MWSI)	49	806	212	NSP	I6
7, 122	Wylie Ridge 500/345 kV XFMR #7 (flo) Wylie Ridge 500/345 kV XFMR #5	0	573	375	PJM	Q9
8, 6009	Cooper South Interface	15	696	234	NPPD	G9
9, 2463	Kokomo HP 230/138 kV XFMR (flo) Jefferson -	0	132	750	CIN	K9

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Pre Market Congestion FG-Hr/YR Jan 01 to Apr 05	1st Year Market Congestion FG-Hr/YR Apr 05 to Apr 06	2nd Year Market Congestion FG-Hr/YR Apr 06 to Apr 07	BA	MTEP Map Grid
	Greentown 765 kV					
10, 2352	Pruntytown - Mt. Storm 500 kV (flo) Black Oak - Bedington 500 kV	0	468	395	PJM, VAP	Q9
11, 3012	Paddock 345/138 kV XFMR (flo) Paddock - Rockdale 345 kV	161	405	420	ALTE	K7
12, none	Culley - Grandview 138 kV (flo) Henderson 161/138 kV XFMR	0	539	284	SIGE	L11
13, 3567	ATC LLC Flow South Interface	1229	646	172	WEC	K5
14, none	Culley - Grandview 138 kV (flo) Henderson - A.B. Brown 138 kV	0	586	84	SIGE	L11
15, 3270	State Line - Wolf Lake 138 kV (flo) Burnham - Sheffield 345 kV	21	151	481	NIPS	L8
16, 3706	Arnold - Hazleton 345 kV	26	112	480	ALTW	I7
17, 3102	Bland - Franks 345 kV	51	347	206	AMRN	I11
18, 6006	Gerald Gentleman Station	4	0	531	NPPD	D9
19, 6085	Genoa - Coulee 161 kV (flo) Genoa-LaCrosse-Marshland 161 kV	51	158	344	DPC	J7
20, 6007	Gerald Gentleman - Red Willow 345 kV	22	271	186	NPPD	D9
21, 1649	Avon 345/138 kV XFMR	0	147	260	EKPC	N11
22, 2557	Northeast Kentucky Interface	0	249	111	LGEE	M11
23, 3108	Overton - Sibley 345 kV	0	160	189	AMRN	H10
24, 2980	Dune Acres -Michigan City 138 kV ckts 1&2 (flo) Wilton Center - Dumont 765 kV	261	241	107	NIPS	L8
25, 9159	Ontario - ITC Interface	8	79	251	DECO	O7
26, 13746	Genoa - Lacrosse Tap 161 kV (flo) JPM unit	0	0	325	DPC	J6
27, 3724	Arnold - Vinton 161 kV (flo) Arnold - Hazelton 345 kV	180	105	216	ALTW	I7
27, 3745	Lime Creek - Emery 161 kV (flo) Adams - Hazleton 345 kV	1	30	291	ALTW	H7
29, none	Kelly - Whitcomb 115 kV (flo) Rocky Run - Werner West 345 kV	0	264	34	WPS	K6
30, 6124	Tiffin - Arnold 345 kV	25	0	271	MEC	I8
31, 2908	Miami Fort 345/138 kV XFMR (flo) East Bend - Terminal 345 kV	43	247	20	CIN	N10
32, 3168	St. Francis - Lutesville 345 kV (flo) Bland - Franks 345 kV	37	151	113	AMRN	K11
33, 2198	Blue Lick 345/161 kV XFMR (flo) Baker - Broadford 765 kV	155	62	189	LGEE	N11
34, none	Oak Creek 345/230 XFMR (flo) Oak Creek 230/138 kV XFMR #851	0	240	0	WEC	L7
35, 3529	North Appleton - Werner West 345 kV	14	8	225	WEC	K6
36, 2072	New London - Webster 230 kV (flo) Jefferson - Greentown 765 kV	0	137	92	CIN	K9
37, 2295	A.B. Brown - Henderson 138 kV (flo) Culley - Grandview 138 kV	9	220	6	SIGE	L11
38, 2357	Wylie Ridge 500/345 kV XFMR #7 (flo) Wylie Ridge 500/345 kV XFMR #5	0	50	169	PJM	Q9

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Pre Market Congestion FG-Hr/YR Jan 01 to Apr 05	1st Year Market Congestion FG-Hr/YR Apr 05 to Apr 06	2nd Year Market Congestion FG-Hr/YR Apr 06 to Apr 07	BA	MTEP Map Grid
39, 2337	Cook - Palisades 345 kV (flo) Benton Harbor - Palisades 345 kV	4	96	117	CONS	L8
40, 2284	Blue Lick - Bullitt Co. 161 kV	0	0	211	EKPC, LGEE	M11
41, 2564	Goddard - Rodburn 138 kV (flo) Avon-Boonesboro-Dale 138 kV	0	0	207	LGEE	
42, 3186	West Mt. Vernon - E W Frankfort 345 kV	0	188	12	AMRN	L10
42, none	Crossville - Albion 138 kV (flo) Mt. Vernon - West Frankfort 345 kV	0	191	9	AMIL	L11
44, none	Hazelton - Arnold 345 kV (flo) Sherco Unit #3	0	22	176	ALTW	I7
45, 2528	Culley - Grandview 138 kV (flo) Henderson 161/138 kV XFMR	6	164	33	SIGE	L11
46, 2375	Wylie Ridge 500/345 kV XFMR #5 (flo) Belmont - Harrison 500 kV	0	161	27	PJM	Q9
46, 3145	Pana 345/138 kV XFMR (flo) Coffeen - Coffeen North 345 kV	0	24	164	AMRN	
48, 6169	Hills - Montezuma 345 kV	0	118	68	MEC	I8
49, 3138	Montgomery - Guthrie 161 kV (flo) Montgomery - McCredie 345 kV	2	88	97	AMRN	J11
50, none	Havana - Mason City W 138 kV - Havana-Canton S-Monmouth 138 kV	0	183	0	AMRN	J9
51, 3184	Overton 345/161 kV XFMR (flo) Overton - Sibley 345 kV	0	25	156	AMRN	
52, 2089	Clifty Creek - Trimble County 345 kV	2	175	1	LGEE	N10

Note: The abbreviation (flo) in table above is for “for loss of”. Certain flowgates have both a limiting or monitored element listed first and a contingent element after the flo.

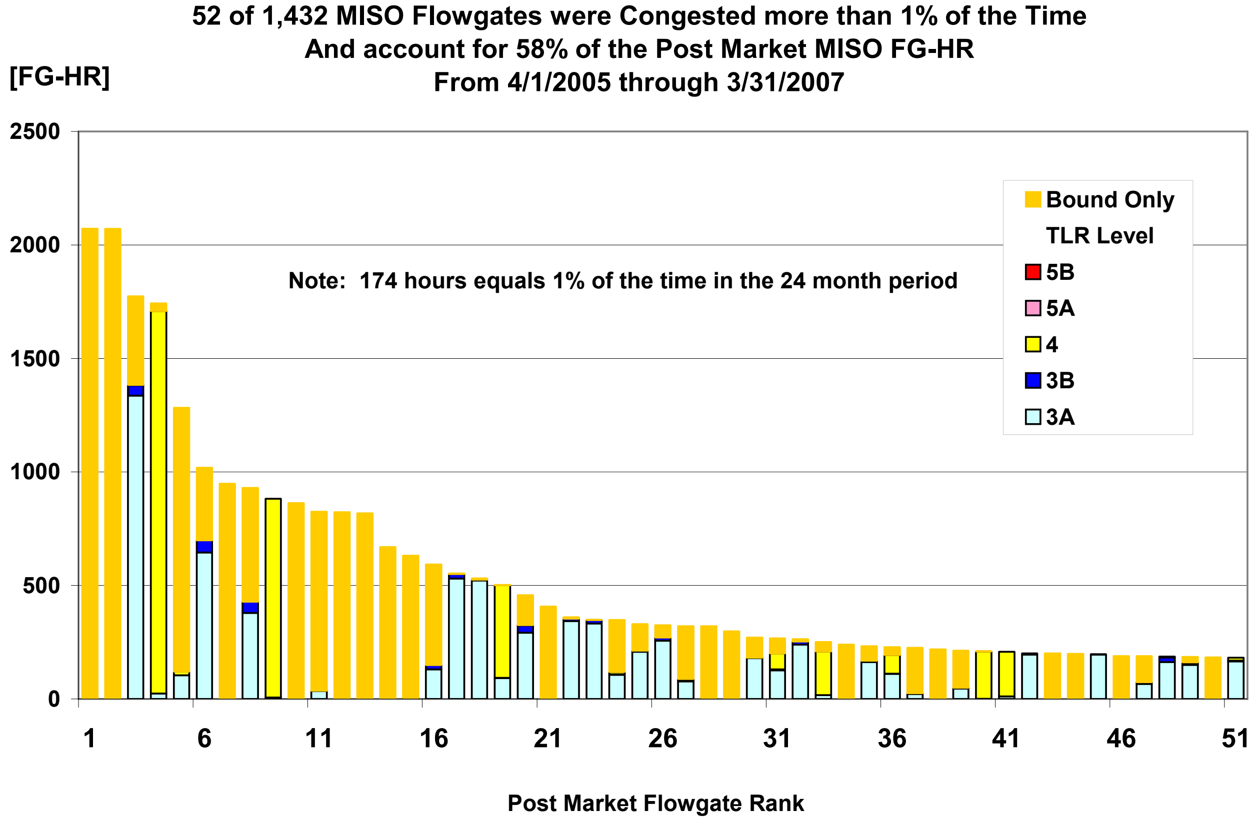

Figure 3.3-3 Top 52 Most Congested Post Market FGs
See Table 3.3-2 for Identification of a Specificly Ranked FG

Note: X-axis lable is count of FGs as sorted, where as the true “Rank number” which accounts for FGs tying for a Rank position are reflected in Table 3.3-2. Example the first two FGs share the number one “Rank” and the third FG in Table 3.3-2 has “Rank” 3. The number 2 “Rank” is skipped in Table 3.3-2.

As previously pointed out, the lag in business activity between the Midwest ISO market footprint and the bordering non-Midwest ISO market participant precipitated an elevated amount of congestion during the first six months of the Midwest ISO market. Therefore, the following review will separate congestion during the first and second Midwest ISO market years, and discuss the changes between the first and second years. For the 25 most congested post Midwest ISO market flowgates, Figure 3.3-4 illustrates the average annual congestion hours for three periods of time: the pre-Midwest ISO market period, 1st Market year, and 2nd Market year.

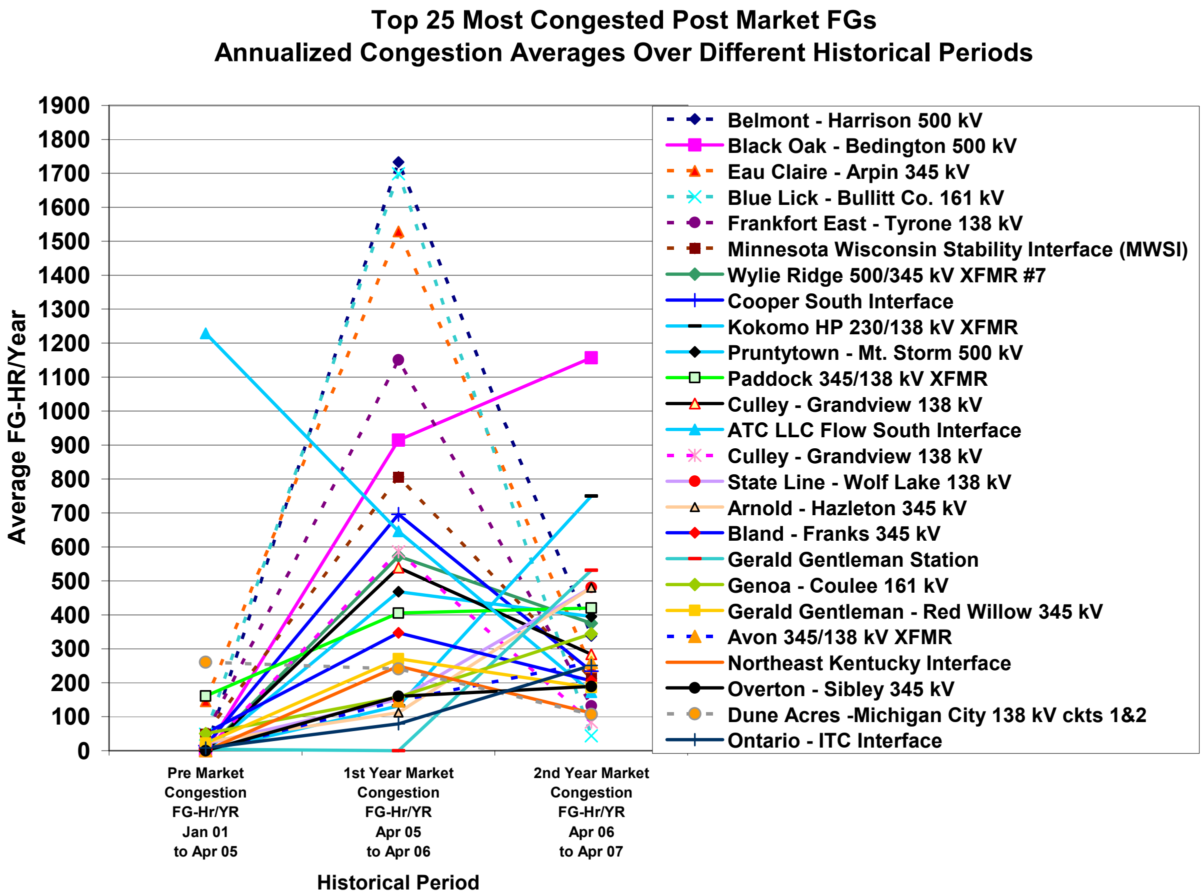

Figure 3.3-4 Top 25 Most Congested Post Market FGs
Annualized Congestion Averages Catagorized into Different Historical Periods

In spite of the elevated congestion activity for the first six months of the Midwest ISO market, some flowgate clearly showed increased activity form the 1st year to the 2nd year. Figure 3.3-5 shows ten of the top 25 most congested post Midwest ISO market congested flowgates that realized increased congestion in the second year, and also realize an annual rate of congestion higher than realized in the pre-Midwest ISO market period. Figure 3.3-6 illustrates the general location with post Midwest ISO market ranking, and NERC ID number noted for the ten 2nd year flowgates that increased in the 2nd Market year. Figure 3.3-7 illustrates 2nd year flowgate hours for those 10 on an MTEP map grid with reference to state boundaries.

Some caution is in order because two years of data only allows perception of one trend point. Fore example, longer term tracking of individual flowgates in the pre-Midwest ISO market time frame had shown that volatile congestion hours can occur for specific time frames. The itemized monthly congestion history for the ten flowgate that realized increased congestion in the 2nd Market year over the 1st Market year are shown in the following Figures 3.3-8 through 3.3-17. A review of the data from these Figures and possible review of other aspects of operation would be needed before predicating specific expansion decisions upon congestion as a driver.

Appendix E1 is a compendium of additional individual flowgate histories like Figures 3.3-8 through 3.3-17 and other charts, including a lookup table "MTEP07_Congestion_Summary.xls" spread sheet for hours congested on each of 1,672 flowgates.

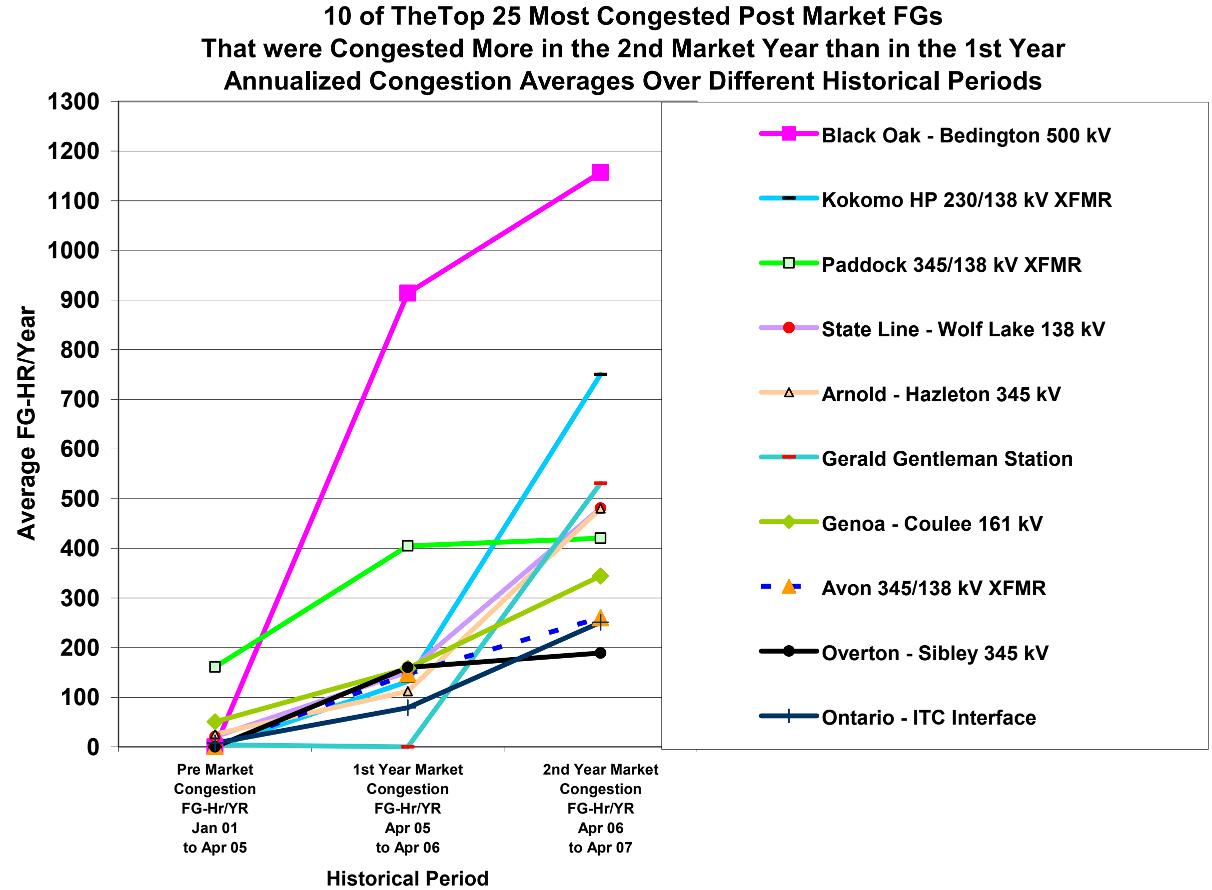

Figure 3.3-5 Of the Top 25 Most Congested Post Market FGs
Ten FG that were Congested More in the 2nd Market Year thanin the 1st Year
Annualized Congestion Averages Over Different Historical Periods

Location of Top 10 FG that Increased
Compared to 1st Market Year

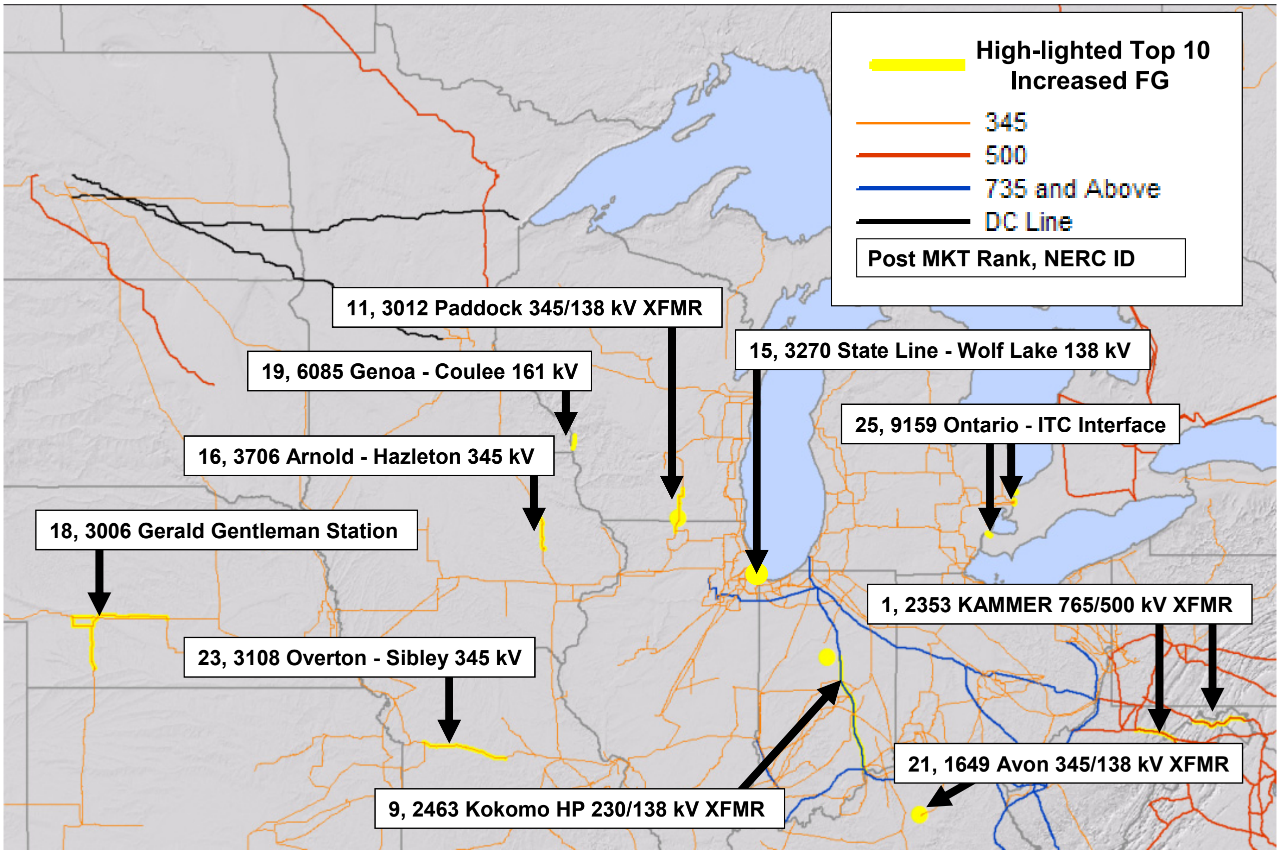

Figure 3.3-6 Location of Ten of the Top 25 Most Congested Post Market FG That Realized Increased Congestion in the 2nd Market Year over the 1st Year

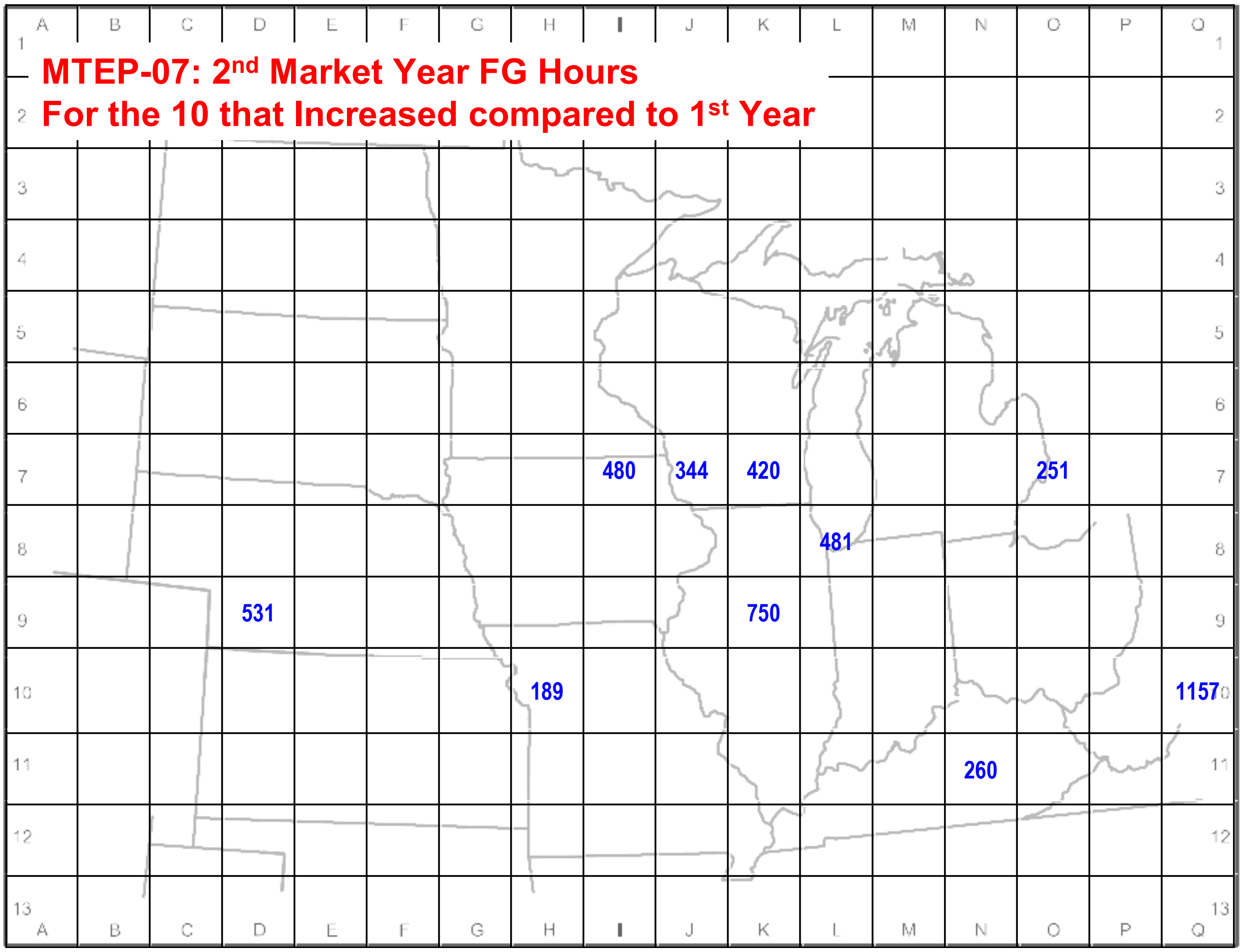

Figure 3.3-6 Location and 2nd Year FG Hours For The Ten of the Top 25 Most Congested Post Market FG that Realized Increased Congestion in the 2nd Market Year over the 1st Year

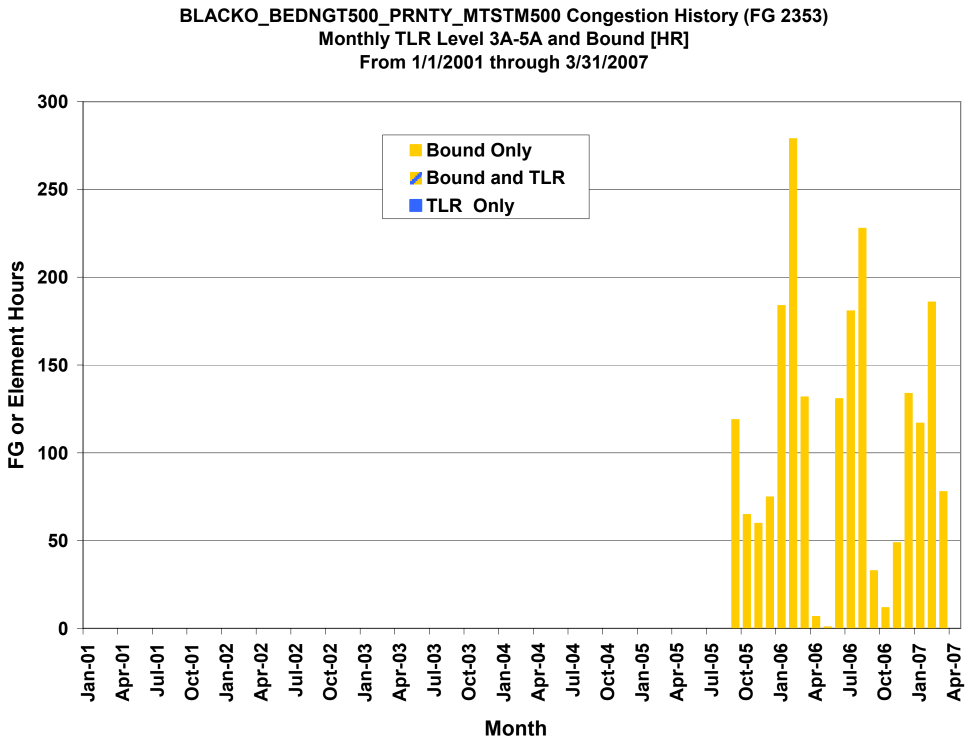

Figure 3.3-8 Itemization of Black Oak - Bedington 500 kV TLR versus Bound, Tied for Post Market Rank =1

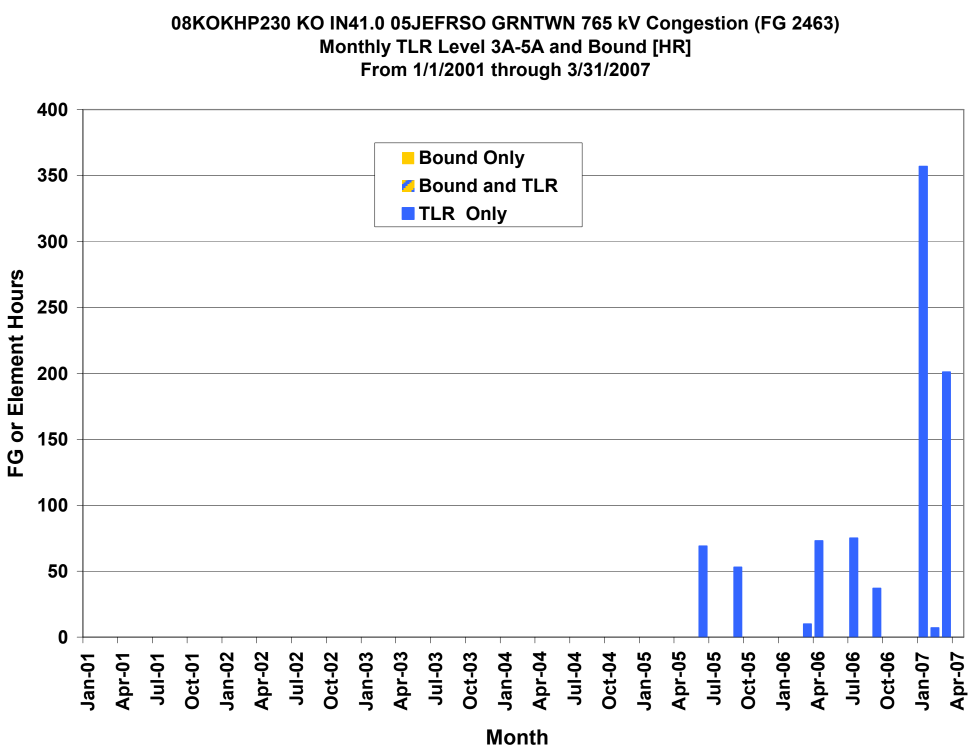

Figure 3.3-9 Itemization of Kokomo HP 230/138 kV XFMR TLR Versus Bound, Post Market Rank = 9

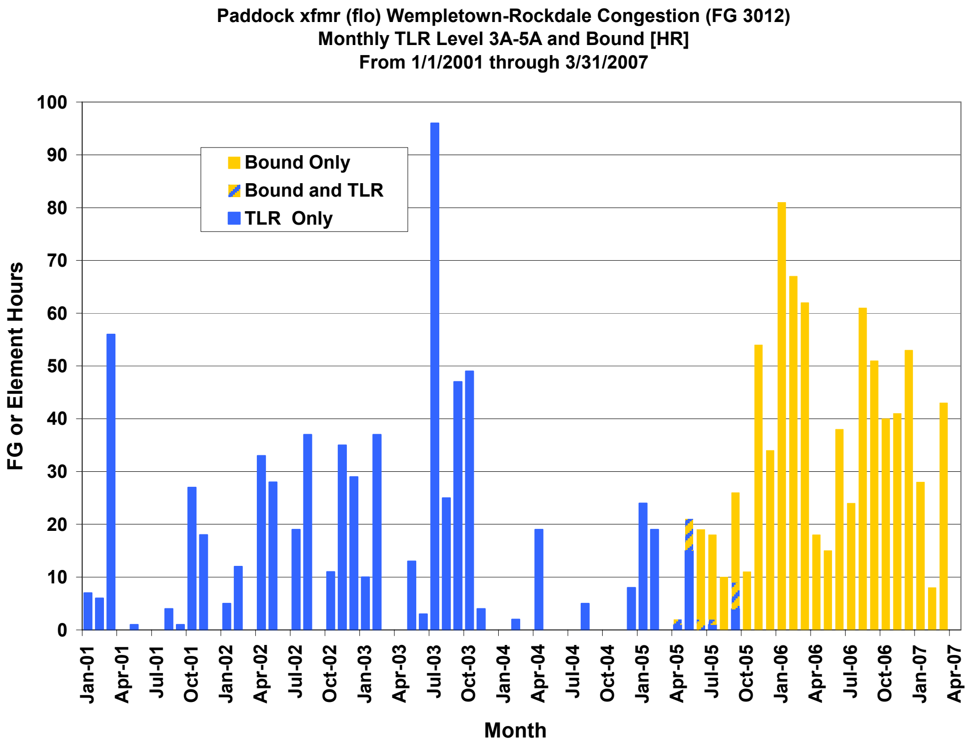

Figure 3.3-10 Itemization of Paddock 345/138 kV XFMR TLR versus Bound, Post Market Rank =11

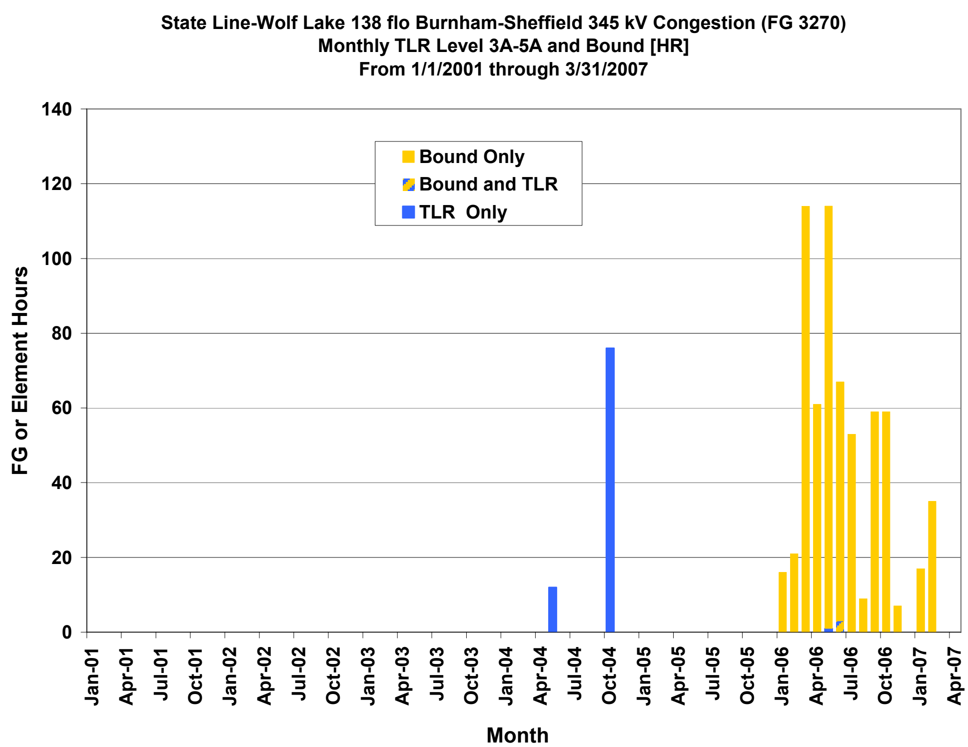

Figure 3.3-11 Itemization of State Line - Wolf Lake 138 kV TLR Versus Bound, Post Market Rank = 15

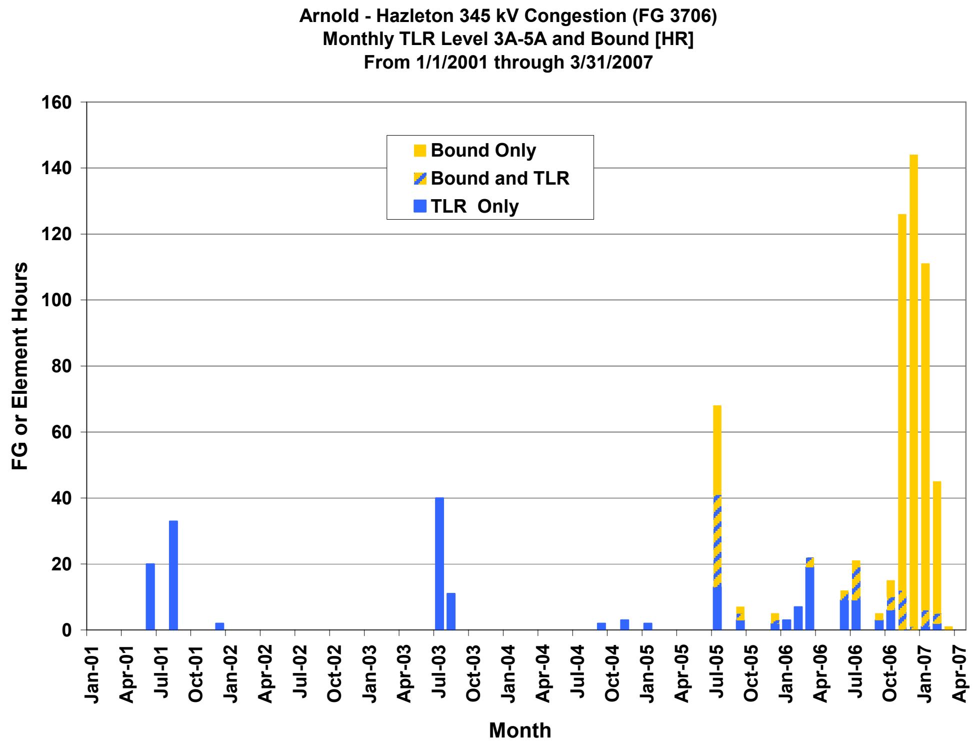

Figure 3.3-12 Itemization of Arnold - Hazleton 345 kV TLR versus Bound, Post Market Rank =16

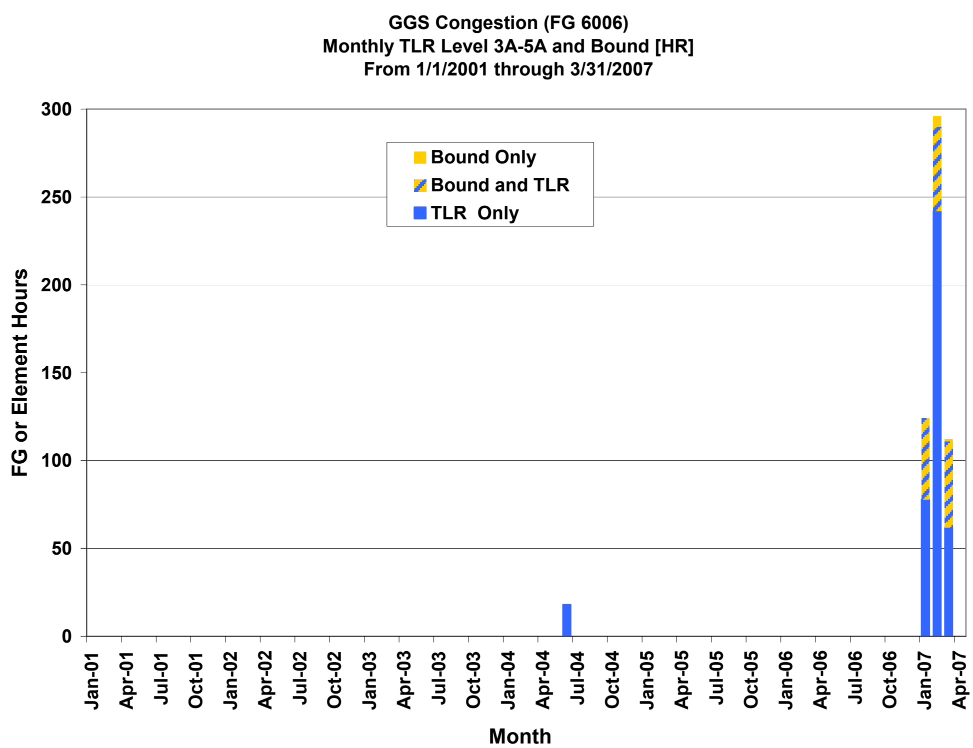

Figure 3.3-13 Itemization of Gerald Gentleman Station (GGS) TLR Versus Bound, Post Market Rank = 18

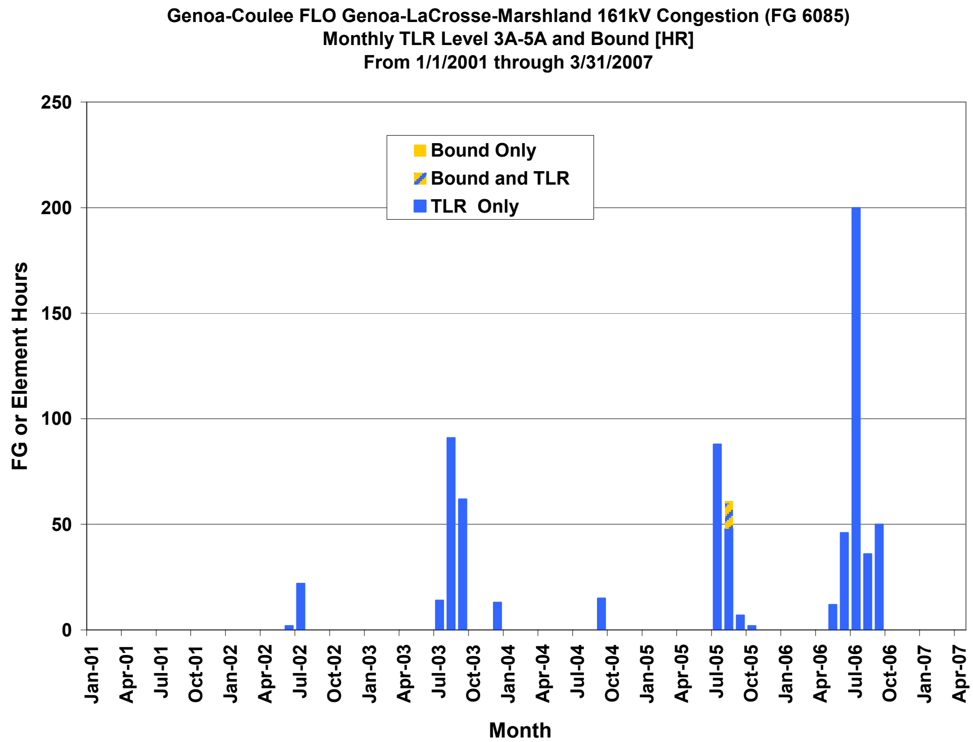

Figure 3.3-14 Itemization of Genoa - Coulee 161 kV TLR versus Bound, Post Market Rank =19

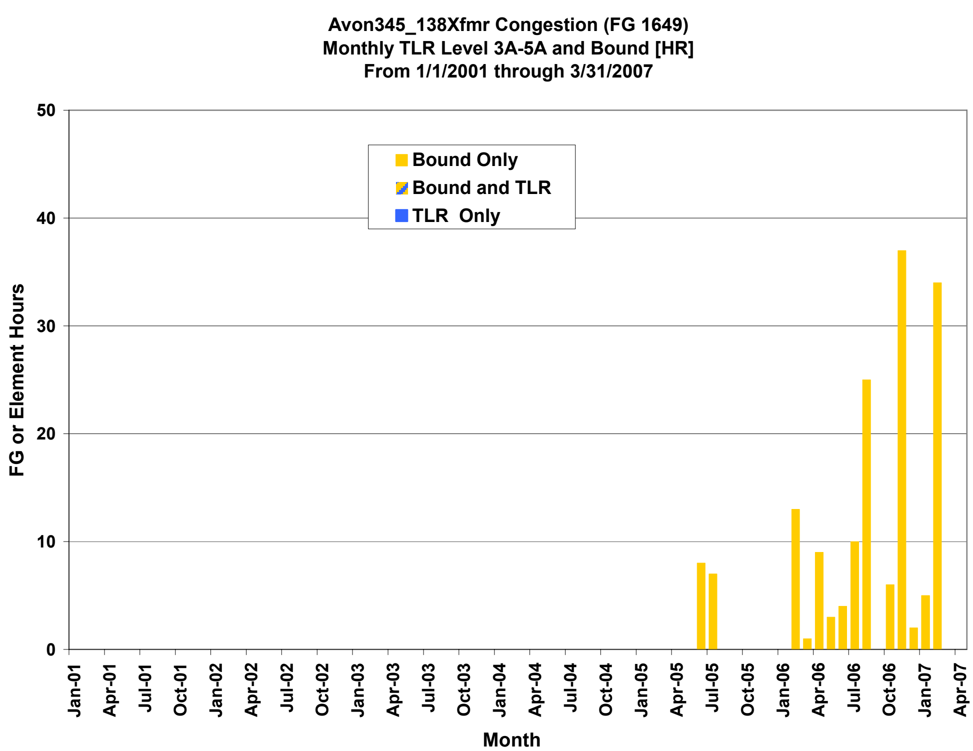

Figure 3.3-15 Itemization of Avon 345/138 kV XFMR TLR Versus Bound, Post Market Rank = 21

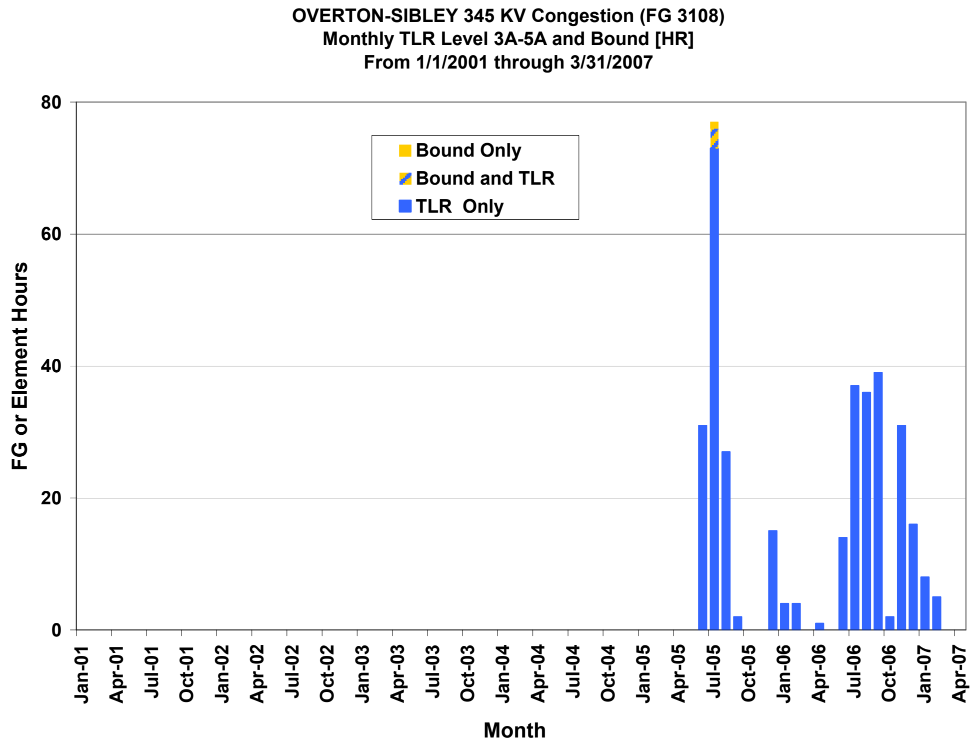

Figure 3.3-16 Itemization of Overton - Sibley 345 kV TLR versus Bound, Tied for Post Market Rank =23

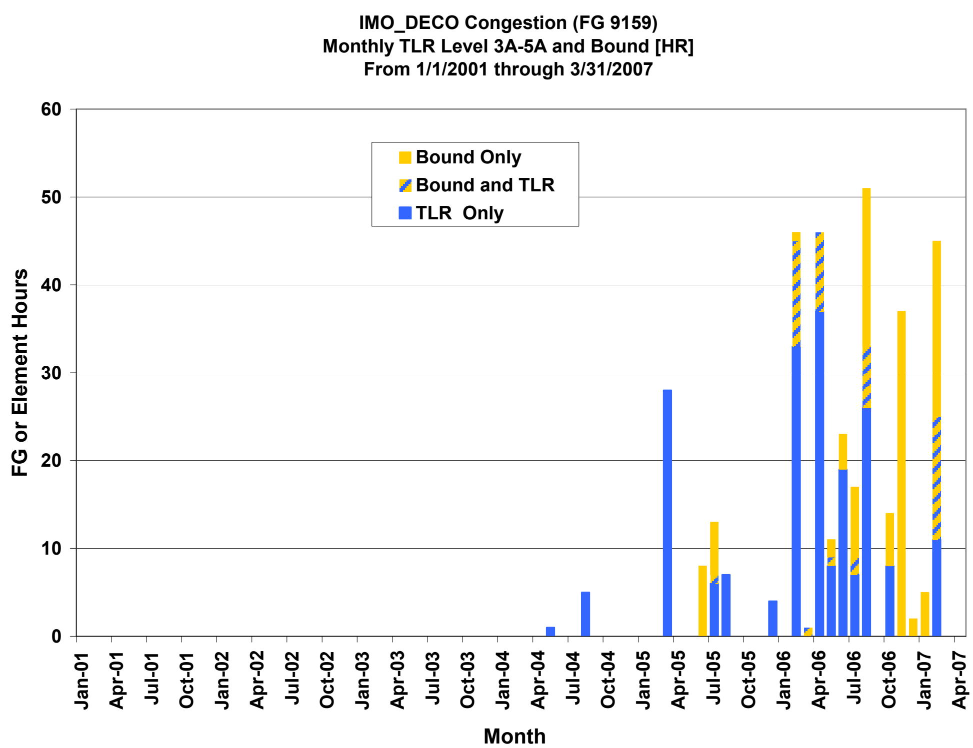

Figure 3.3-17 Itemization of Ontario - ITC Interface TLR versus Bound, Tied for Post Market Rank =25

3.3.2. View of Future Congestion

The historical constraint overview in Section 3.3.1 demonstrates that there are opportunities for improving the performance of the energy market. Significant transmission system upgrades are planned, primarily to address baseline reliability concerns, in future years. Table 3.3-3 lists the future planned or proposed facilities that are expected to mitigate some of congestion on the top 52 historically most congested post-Midwest ISO market flowgates previously listed in Table 3.3-2.

Table 3.3-3 The 52 Post Market Flowgates That on the Average were Congested More Than 1% of the Time With Correlation to Expansion Projects which may mitigate Constrained Hours in the Future

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Sum of 1st and 2nd Market Years Hours Congested	Related Upgrades/Comments
1, 100	Kammer 765/500 kV XFMR (flo) Belmont - Harrison 500 kV	2,071	Not Midwest ISO flowgate
1, 2353	Black Oak - Bedington 500 kV (flo) Pruntytown - Mt. Storm 500 kV	2,071	Not Midwest ISO flowgate
3, 3006	Eau Claire - Arpin 345 kV	1,774	P1: Arrowhead - Gardner Park 345 kV line
4, 2245	Blue Lick - Bullitt Co. 161 kV (flo) Baker - Broadford 765 kV	1,743	Not Midwest ISO flowgate
5, 2872	Frankfort East - Tyrone 138 kV (flo) Ghent - West Lexington 345 kV	1,283	Not Midwest ISO flowgate
6, 6004	Minnesota Wisconsin Stability Interface (MWSI)	1,018	P1024: SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV project
7, 122	Wylie Ridge 500/345 kV XFMR #7 (flo) Wylie Ridge 500/345 kV XFMR #5	948	Not Midwest ISO flowgate
8, 6009	Cooper South Interface	930	Not Midwest ISO flowgate
9, 2463	Kokomo HP 230/138 kV XFMR (flo) Jefferson - Greentown 765 kV	882	No proposed projects at this time.
10, 2352	Pruntytown - Mt. Storm 500 kV (flo) Black Oak - Bedington 500 kV	863	Not Midwest ISO flowgate
11, 3012	Paddock 345/138 kV XFMR (flo) Paddock - Rockdale 345 kV	825	2nd Wempletown - Padock 345 kV line (in service in 2005) and P1256 (Paddock Rockdale 345kV circuit #2
12, none	Culley - Grandview 138 kV (flo) Henderson 161/138 kV XFMR	823	P1259: New transmission line Dubois to Newtonville, ISD June 2006.
13, 3567	ATC LLC Flow South Interface	818	Stiles - Plains 138 kV dbl cks rebuilt project was in service in 2006, which increase the ME ratings by three times. P177 (Gardner Park- Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) connect Morgan - Plains 345 kV line to the pre-existing 345 kV system, hence increase voltage stability. P352 (Cranberry-Conover 115 kV and Conover-Plains conversion to 138 kV) and P888 (Plains second 345/138 kV transformer) will also help increase the FG limit.
14, none	Culley - Grandview 138 kV (flo) Henderson	670	P1259: New transmission line Dubois to Newtonville,

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Sum of 1st and 2nd Market Years Hours Congested	Related Upgrades/Comments
	- A.B. Brown 138 kV		ISD: June 2006.
15, 3270	State Line - Wolf Lake 138 kV (flo) Burnham - Sheffield 345 kV	632	No project identified
16, 3706	Arnold - Hazleton 345 kV	592	P1340: Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer
17, 3102	Bland - Franks 345 kV	553	No project identified
18, 6006	Gerald Gentleman Station	531	Coordinated Non-MISO flowgate. Driven by ice storm related damage in early 2007, See Figure 3.3-13
19, 6085	Genoa - Coulee 161 kV (flo) Genoa-LaCrosse-Marshland 161 kV	502	P584: Genoa- Coulee 161 kV rebuild. **In Service**
20, 6007	Gerald Gentleman - Red Willow 345 kV	457	Coordinated Non-Midwest ISO flowgate
21, 1649	Avon 345/138 kV XFMR	407	Non-MISO. Planned 2nd Avon 345/138 kV transformer. Expected ISD: June 2009
22, 2557	Northeast Kentucky Interface	360	Not Midwest ISO flowgate
23, 3108	Overton - Sibley 345 kV	349	No project identified
24, 2980	Dune Acres -Michigan City 138 kV ckts 1&2 (flo) Wilton Center - Dumont 765 kV	348	Market Operational Issue during high West to East Transfers
25, 9159	Ontario - ITC Interface	330	Congestion on the tie is caused by transactions beyond firm reservations between Michigan and IESO. Once Bunce Creek Phase Shifter (previously failed) is returned to service (Est. Summer 2009), all four ties on this interface (Currently normally operated with the existing three Phase Shifters by-passed) may be Phase Shifter controlled in order to help limit flows to limit congestion.
26, 13746	Genoa - Lacrosse Tap 161 kV (flo) JPM unit	325	P1559: Genoa-La Crosse tap 161 rebuild. ISD 2011
27, 3724	Arnold - Vinton 161 kV (flo) Arnold - Hazelton 345 kV	321	P1340: Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer
27, 3745	Lime Creek - Emery 161 kV (flo) Adams - Hazleton 345 kV	321	P90: Emery-Lime Crk 161kV, Ckt 2
29, none	Kelly - Whitcomb 115 kV (flo) Rocky Run - Werner West 345 kV	298	P101: Kelly-Whitcomb 115 kV upgrade
30, 6124	Tiffin - Arnold 345 kV	271	P1340: Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer
31, 2908	Miami Fort 345/138 kV XFMR (flo) East Bend - Terminal 345 kV	267	P1248: Miami Fort 21.6MVAR 69kV capacitor. This project can reduce the reactive power flow through the transformer. ISD: Mar 2006
32, 3168	St. Francis - Lutesville 345 kV (flo) Bland - Franks 345 kV	264	No project identified
33, 2198	Blue Lick 345/161 kV XFMR (flo) Baker - Broadford 765 kV	251	Not Midwest ISO flowgate
34, none	Oak Creek 345/230 XFMR (flo) Oak Creek 230/138 kV XFMR #851	240	No project identified
35, 3529	North Appleton - Werner West 345 kV	233	P345: Morgan - Werner West 345 kV line P177: Gardner Park-Highway 22 345 kV line
36, 2072	New London - Webster 230 kV (flo) Jefferson - Greentown 765 kV	229	P1561: complete the Webster Street ring in order to utilize the full capacity of the bundled 477 ACSS wire on the 23016 line.
37, 2295	A.B. Brown - Henderson 138 kV (flo) Culley	226	P1257: New transmission line Gibson (Cinergy) to AB Brown to

Post MKT Rank, NERC ID	FLOWGATE Name/Description	Sum of 1st and 2nd Market Years Hours Congested	Related Upgrades/Comments
	- Grandview 138 kV		Reid (BREC). ISD is Jun 2006.
38, 2357	Wylie Ridge 500/345 kV XFMR #7 (flo) Wylie Ridge 500/345 kV XFMR #5	219	Not Midwest ISO flowgate
39, 2337	Cook - Palisades 345 kV (flo) Benton Harbor - Palisades 345 kV	213	Cook to Palisades 345 kV line overloads for the loss of Benton Harbor to Palisades 345 kV line has not been seen as an issue in contractual dispatch baseline reliability analysis. Issues result from large South to North flow bias into Michigan such as scenarios when Ludington units are pumping
40, 2284	Blue Lick - Bullitt Co. 161 kV	211	Not Midwest ISO flowgate
41, 2564	Goddard - Rodburn 138 kV (flo) Avon-Boonesboro-Dale 138 kV	207	Not Midwest ISO flowgate
42, 3186	West Mt. Vernon - E W Frankfort 345 kV	200	P739: The Franklin County plant interconnection includes a 345kV switchyard and "in and out" connection to the Mt. Vernon - E W Frankfort 345kV line. Impact on flowgate TBD
42, none	Crossville - Albion 138 kV (flo) Mt. Vernon - West Frankfort 345 kV	200	No project at this time
44, none	Hazelton - Arnold 345 kV (flo) Sherco Unit #3	198	P1340: Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer
45, 2528	Culley - Grandview 138 kV (flo) Henderson 161/138 kV XFMR	197	P1259: New transmission line Dubois to Newtonville, ISD June 2006.
46, 2375	Wylie Ridge 500/345 kV XFMR #5 (flo) Belmont - Harrison 500 kV	188	Not Midwest ISO flowgate
46, 3145	Pana 345/138 kV XFMR (flo) Coffeen - Coffeen North 345 kV	188	P1523: Coffeen-Pana, North-Upgrade terminal equipment ISD: April 2007.
48, 6169	Hills - Montezuma 345 kV	186	Not Midwest ISO flowgate
49, 3138	Montgomery - Guthrie 161 kV (flo) Montgomery - McCredie 345 kV	185	P 78: Moreau - Apache Flats 161 kV line, Loose Creek - Jefferson City 345 kV line, Jefferson City 345/161kV transformer. In Service
50, none	Havana - Mason City W 138 kV - Havana-Canton S-Monmouth 138 kV	183	P 1234: Havana, South-Mason City, West 138 kV Increase ground clearance on 18.4 miles.
51, 3184	Overton 345/161 kV XFMR (flo) Overton - Sibley 345 kV	181	P 78: Moreau - Apache Flats 161 kV line, Loose Creek - Jefferson City 345 kV line, Jefferson City 345/161kV transformer. In Service
52, 2089	Clifty Creek - Trimble County 345 kV	176	Not Midwest ISO flowgate

There are many flowgates listed above which are not on Midwest ISO system, yet they are listed to show the opportunity for coordinating with neighboring systems to improve energy market performance. Midwest ISO will work with neighboring systems to determine which flowgates may be cost effectively mitigated and provide value to the Midwest ISO market. Analysis in MTEP08 will focus on providing solutions to Midwest ISO market constraints.

While Table 3.3-3 indicates which MTEP expansion planning projects will tend to mitigate congestion on flowgates that have been historically congested, a simulation of 2013 was done do reveal where congestion might most likely realized in 2013. Table 3.3-4 lists the top 20 congested flowgates in the 2013 simulation. Comments address if there has been any historical Midwest RA congestion activity since 2001, and what (if any) the congestion hours were for the 2nd Market year. The 2013 model included all planned projects, however not all proposed projects were included in the run. Additional study will continue to determine the effectiveness of additional proposed facilities. For example the completed 2013 simulation suggests that the proposed Hazelton – Salem 345 kV line in Iowa would be helpful to mitigate congestion on some of the flowgates appearing in Table 3.3-4.

Annual congestion hours from a simulation and congestion hours from Real Time congestion are not the same metric. The simulated hours and historical Real Time congested hours in Table 3.3-4 are only for benchmarking the common locations in the 2nd Market year versus estimates of the year 2013. Where congestion hours occur in both the 2013 simulation and the Real Time values from the 2nd Market year, the hours from the simulation are much larger than the Real Time Market hours. The large difference in congestion hours is due to the fact that simulations have no ability to recognize transmission service limitations that limit BA to BA schedules by tracking various AFC limits and refuse service. The simulation also does not benefit from a Day Ahead Market screening effects. Therefore, the simulation represents an LMP dispatch of the eastern interconnection where all AFC values are infinity large, and accounts for all limitations in the form of congestion hours within the LMP market simulation proper. By necessity the simulation is a model of the entire transmission network as one LMP market absent an OASIS system, because there would be no need for Point to Point transmission service.

Table 3.3-4 The 20 Top Constrained FG
In Year 2013 Reference Case PROMOD Simulation

Year 2013 PROMOD Case Rank, NERC ID	FLOWGATE Name/Description (Monitored Element)	Simulation Area(s)	2013 Case Hours Congested	Related Comments
1, 6088	Genoa-Seneca 161 and Eau Claire-Arpin 345	DPC, XCEL-ALTE	5168	No MISO RA historical congestion
2, 5008	Craig Jct - Ashdown West 138 kV	AEPW	4826	No MISO RA historical congestion
3, 5229	Wichita - Woodring 345 kV	WERE-OKGE	3153	No MISO RA historical congestion
4, unknown	Doubs - Aquaduct 230 kV	AP	3044	No MISO RA historical congestion
5, 6189	Adams - Rochester 161 kV	ALTW-DPC	2984	No MISO RA historical congestion
6, 1002	Thomas Hill - Moberly Tap 161 kV	AECI	2539	28 hours in 2nd Market Yr
7, 3147	Mason City - Mt. Pulaski 138 kV	AMRN	2256	9 hours in 2nd Market Yr
8, 6140	Medicine Lodge 138/115 kV XFMR	WEPL	2243	No MISO RA historical congestion
9, 3572	Pleasant Prairie - Zion 345 kV	WEC-ComEd	2100	No MISO RA historical congestion
10, unknown	Newton - Effingham 138 kV	AMRN	2063	0 hour in 2nd Market Yr
11, unknown	Roxbury - Greene 138 kV	PENELEC-AP	2058	No MISO RA historical congestion
12, unknown	W. Mt. Vernon - Ashley 138 kV	AMRN	2010	No MISO RA historical congestion
13, unknown	Waldwick - Hawthorne 230 kV	PSEG	1987	No MISO RA historical congestion
14, 230	Breed - Wheatland 345 kV	AEP-IPL	1967	1 hour in 2nd Market Yr
15, 2980	Dune Acres -Michigan City 138 kV ckts 1&2	NIPS	1963	107 hours in 2nd Market Yr
16, 1501	Conasaga - Sequoyah 500 kV	SOCO-TVA	1820	No MISO RA historical congestion
17, 6145	Lake Road - Nashua 161 kV	MIPU-KACP	1781	0 hour in 2nd Market Yr
18, 3428	Galesburg 161/138 kV XFMR #2	MEC-AMRN	1699	No MISO RA historical congestion
19, unknown	Cedar Grove - Clifton 230 kV	PSEG	1595	No MISO RA historical congestion
20, 5015	El Paso - Farber 138 kV	WERE	1593	No MISO RA historical congestion
21, 1638	Shelby - Dell 500 kV	TVA-EES	1592	No MISO RA historical congestion
22, 2974	Dune Acres - Michigan City 138 kV	NIPS	1519	42 hours in 2nd Market Yr
23, 2556	Newton - Casey 345 kV	AMRN	1456	1 hour in 2nd Market Yr
24, 5035	Montrose - Clinton Gravois 161 kV	KACP-AECI	1442	No MISO RA historical congestion
25, 3145	Pana 345/138 kV XFMR	AMRN	1434	164 hours 2nd Market Yr

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3.4 Narrow Constrained Areas

A Narrow Constrained Area (NCA) is defined as: "An electrical area that has been identified by the Independent Market Monitor (IMM) that is defined by one or more Binding Transmission Constraints that are expected to be binding for at least five hundred (500) hours during a given year and within which one or more suppliers are pivotal."

Currently, there are three NCAs defined by the Independent Market Monitor in Midwest ISO footprint: the Wisconsin Upper Michigan System (WUMS), Northern WUMS, and an NCA described as SE_MN/N_IA/SW_WI which includes portions of southeast Minnesota, northern Iowa, and southwestern Wisconsin.

Future planned or proposed facilities that are expected to mitigate transmission constraints defined in these three NCAs are listed below each NCA flowgate list. These upgrades are expected to relieve specified constraints defining the NCA either because the constraint was the same as the constraint found in prior reliability studies that justified the reliability upgrade, or because the upgrade provides a parallel path to the constrained flowgate and can therefore be expected to provide relief. Where such upgrades are put in place there is a high degree of confidence that these NCA flowgate constraints will be relieved. Future MTEP analyses using security constrained dispatch analyses will be required to confirm, however, whether any of the NCA flowgates are expected to bind with the upgrade in place and under projected market conditions.

3.4.1 WUMS Narrow Constrained Area

The WUMS NCA was defined by David B. Patton in his affidavit testimony filed by the Midwest ISO (Docket No. ER04-691-000). The WUMS NCA includes 15 flowgates (Table 3.4-1) that significantly limit imports into WUMS. The list of Generation Resources in the WUMS NCA is in Appendix E2 (Gen_NCA_WUMS.pdf)

Table 3.4-1
Flowgates included in WUMS NCA

FG ID	NCA	Flowgate Description
3001	WUMS NCA	Wempletown-Paddock 345 kV
3006	WUMS NCA	Eau Claire-Arpin 345 kV
3012	WUMS NCA	Paddock XFMR 1 + Paddock-Rockdale
3015	WUMS NCA	Nelson Dewey XFMR+Wempletown-Paddock
3017	WUMS NCA	Cassvl-NED 161 FLO Wempletown-Paddock 345
3025	WUMS NCA	Russel-Rockdale 138/Paddock-Rockdale 345
3034	WUMS NCA	Blackhawk-Colleyrd Xfmr FLO Paddock-Rockdale345
3241	WUMS NCA	2221 Zion-Plsp FLO 17101 Wempletown-Paddock
3522	WUMS NCA	Albers-Paris138 FLO Wempletown-Padock 345
3527	WUMS NCA	PleasPr-Racine 345 FLO Wempletown-Pad 345
3534	WUMS NCA	Kenosha-Albers 138 FLO Wempletown-Paddock 345
3565	WUMS NCA	Paris-Burlington 138 FLOWempletown-Paddock 345
3705	WUMS NCA	Arnold-Hazelton 345 FLO Wempletown-Paddock 345
3707	WUMS NCA	Lore-Turkey River 161 FLO Wempletown-Paddock 345
3736	WUMS NCA	Salem 345/161 FLO Wempletown-Paddock 345

FLO is abbreviation for 'For Loss Of' or outage of the following element

There are some future projects identified in MTEP studies that are expected to provide relief to these 15 constraints. These projects are listed in Table 3.4-2.

Table 3.4-2 Projects to Relieve WUMS NCA

FG ID	Flowgate Description	Potential Solutions	Expected ISD	App AB
3001	Wempletown-Paddock 345 kV	2nd Wempletown - Padock 345 kV line (in service in 2005) and P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path	4/1/2010	A
3006	Eau Claire-Arpin 345 kV	P1 (Arrowhead - Gardner Park 345 kV line) provides a parallel path	6/30/2008	A
3012	Paddock XFMR 1 + Paddock-Rockdale	P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path for CE	4/1/2010	A
3015	Nelson Dewey XFMR+Wempletown-Paddock	New 161 kV line Nelson Dewey - Liberty (P1617) provides relief for ME	6/1/2011	A
3017	Cassvl-NED 161 FLO Wempletown-Paddock 345	New 161 kV line Nelson Dewey - Liberty (P1617) provides a parallel path for ME	6/1/2011	A
3025	Russel-Rockdale 138/Paddock-Rockdale 345	P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path of CE	4/1/2010	A
3034	Blackhawk-Colleyrd Xfmr FLO Paddock-Rockdale345	P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path of CE	4/1/2010	A
3241	2221 Zion-Plsp FLO 17101 Wempletown-Paddock	2nd Wempletown - Padock 345 kV line (in service in 2005) and P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path of CE	4/1/2010	A
3522	Albers-Paris138 FLO Wempletown-Padock 345	2nd Wempletown - Padock 345 kV line (in service in 2005) and P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path of CE	4/1/2010	A
3527	PleasPr-Racine 345 FLO Wempletown-Pad 345	2nd Wempletown - Padock 345 kV line (in service in 2005) and P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path of CE	4/1/2010	A
3534	Kenosha-Albers 138 FLO Wempletown-Paddock 345	2nd Wempletown - Padock 345 kV line (in service in 2005) and P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path of CE	4/1/2010	A
3565	Paris-Burlington 138 FLO Wempletown-Paddock 345	2nd Wempletown - Padock 345 kV line (in service in 2005) and P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path of CE	4/1/2010	A
3705	Arnold-Hazelton 345 FLO Wempletown-Paddock 345	2nd Wempletown - Padock 345 kV line (in service in 2005) and P1256 (Paddock - Rockdale 345kV circuit #2) provides the 2nd path of CE	4/1/2010	A
3707	Lore-Turkey River 161 FLO Wempletown-Paddock 345	New 161 kV line Nelson Dewey - Liberty (P1617) provides a parallel path of ME	6/1/2011	A
3736	Salem 345/161 FLO Wempletown-Paddock 345	P1287 (Replace Salem 345/161 kV transformer with 448 MVA unit) increases ratings of ME.	6/1/2008	A

ME, CE are abbreviation for 'Monitored Element' and 'Contingency Element'

3.4.2 Northern WUMS Narrow Constrained Area

The Northern WUMS NCA was defined by David B. Patton in his affidavit testimony filed by the Midwest ISO (Docket No. ER04-691-000). The Northern WUMS NCA includes 12 flowgates (Table 3.4-3) that significantly limit imports into Northern Wisconsin and the Upper Peninsula of Michigan. The list of Generation Resources in the Northern WUMS NCA is in Appendix E2 (Gen_NCA_Northern_WUMS.pdf)

Table 3.4-3
Flowgates included in Northern WUMS NCA

FG ID	NCA	FG Description
3030	North WUMS	Green Lk-Roeder 138 for N Appleton-RoR 345
3523	North WUMS	Stiles-Pioneer 138 For N.Appl-Whiteclay138
3525	North WUMS	Stiles-Amberg 138 For Morgan-Plains 345
3528	North WUMS	N Appleton-White Clay 138 For Stiles-Pulliam 138 #64451
3535	North WUMS	N.Appleton-Lost Dauphin 138 For Kewaunee 345-138 TR
3538	North WUMS	Pulliam4-Stiles 138 (Flo) Pulliam5-Stiles 138
3544	North WUMS	Stiles-Amberg 138 & Stiles-Crivitz 138 Flo Morgan-Plains 345
3567	North WUMS	Flow South
3611	North WUMS	Kewaunee 345/138 Xfmr
3613	North WUMS	Kewaunee XFMR+Kewaunee-N Appleton
3617	North WUMS	Highwayv-Preble+N Appltn-White Clay
3631	North WUMS	Highway V - Preble 138 (Flo) Lost Dauphin - Red Maple 138

There are some future projects that are expected to provide relief to these 12 constraints. These projects are listed in Table 3.4-4.

Table 3.4-4
Projects to Relieve Northern WUMS NCA

FG ID	FG Description	Potential Solutions	Expected ISD	App AB
3030	Green Lk-Roeder 138 for N Appleton-RoR 345	P177 (Gardner Park-Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) will relieve the loading on Green Lake – Roeder 138 kV line for the loss of North Appleton – Werner West – Rocky Run 345 kV line	12/1/2009	A
3523	Stiles-Pioneer 138 For N.Appl-Whiteclay138	P177 (Gardner Park-Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) connect Morgan - Plains 345 kV line to the pre-existing 345 kV system, hence relieve the flow on Stiles - Pioneer 138 kV parallel path	12/1/2009	A
3525	Stiles-Amberg 138 For Morgan-Plains 345	Stiles - Plains 138 kV rebuilt project was in service in 2006, which increase the ME ratings by three times	2006	Completed
3528	N Appleton-Wh Clay 138 For Stiles-Pulliam 138 #64451	P567 (North Appleton-Lawn Road-White Clay 138 kV uprate) will increase ME rating. P177 (Gardner Park-Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) connect Morgan - Plains 345 kV line to the pre-existing 345	(P567)2/1/2008 (P177)12/1/2009 (P345)12/1/2009	A A A

FG ID	FG Description	Potential Solutions	Expected ISD	App AB
		kV system, hence relieve the flow on parallel path of CE		
3535	N.Appleton-Lostdauphin 138 For Kewaunee 345-138 TR	P880 (Lost Dauphin-North Appleton-Mason Street 138 kV uprates) will increase ME rating.	6/1/2008	A
3538	Pulliam4-Stiles 138 (Flo) Pulliam5-Stiles 138	P177 (Gardner Park- Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) connect Morgan - Plains 345 kV line to the pre-existing 345 kV system, hence relieve the flow on parallel path of Pulliam - Stiles 138 kV lines	12/1/2009	A
3544	Stiles-Amberg 138 & Stiles-Crivitz 138 Flo Morgan-Plains 345	Stiles - Plains 138 kV dbl cks rebuilt project was in service in 2006, which increase the ME ratings by three times. P177 (Gardner Park- Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) connect Morgan - Plains 345 kV line to the pre-existing 345 kV system, hence relieve the flow on parallel path of ME	2006 12/1/2009	Completed A
3567	Flow South	Stiles - Plains 138 kV dbl cks rebuilt project was in service in 2006, which increase the ME ratings by three times. P177 (Gardner Park- Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) connect Morgan - Plains 345 kV line to the pre-existing 345 kV system, hence increase voltage stability. P352 (Cranberry-Conover 115 kV and Conover-Plains conversion to 138 kV) and P888 (Plains second 345/138 kV transformer) will also help increase the FG limit.	2006 (P177)12/1/2009 (P345)12/1/2009 (P352)12/31/2009 (P888)12/1/2009	Completed A A A B
3611	Kewaunee 345/138 Xfmr	None		
3613	Kewaunee XFMR+Kewaunee-N Appleton	None		
3617	Highway V-Preble+N Appltn-White Clay	P177 (Gardner Park- Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) connect Morgan - Plains 345 kV line to the pre-existing 345 kV system, hence relieve the flows on parallel path of ME	12/1/2009	A
3631	Highway V - Preble 138 (Flo) Lost Dauphin - Red Maple 138	P177 (Gardner Park- Highway 22 345 kV line projects) and P345 (Morgan - Werner West 345 kV line) connect Morgan - Plains 345 kV line to the pre-existing 345 kV system, hence relieve the flows on parallel path of ME	12/1/2009	A

3.4.3 SE_MN / N_IA / SW_WI Narrow Constrained Area

The SE_MN/N_IA/SW_WI NCA was defined by David B. Patton in his affidavit testimony filed by the Midwest ISO on November 20, 2006. The NCA is defined by a set of constraints that limit imports from south to north into Minnesota. According to Dr. Patton's affidavit, two dominant parallel electrical paths that limit such imports were identified. The first path is a series of 345 kV transmission facilities in a path from Raun in western Iowa to Lakefield, to Wilmarth, and to Blue Lake in Southern Minnesota. The second path is a series of 345 kV transmission facilities, from

Tiffin in eastern Iowa to Arnold, to Hazleton, to Adams, to Pleasant Valley, and to Prairie Island in southern Minnesota. The list of transmission constraints that define this NCA is in Table 3.4-5, and is that same as those in Appendix A of Dr. Patton's affidavit. The list of Generation Resources in the SE_MN/N_IA/SW_WI NCA is in Appendix E2 (Gen_NCA_MN-IA-WI.doc)

Table 3.4-5
Transmission Flowgates included in SE_MN/N_IA/SW_WI NCA

ALENSP02_HAZLTON_HAZLTDUNDE 16_1 _1	MEC34018_HAZLTON_HAZLTDUNDE16_1_1
ALENSP1G_HAZLTON_HAZLTDUNDE 16_1_1	MEC34018_SALEM3_TR21_TR21
ALW16001_LIME_CK_LIME_EMERY 16_1_1	MEC34020_ARNOLD_ARNOLVINT016_1 _1
ALW16019_HIAWATA_HIAWADRYC 11_1_1	MEC34020_HAZLTON_HAZLTDUNDE16_1_1
ALW 16042_FOX_LK_TR92_TR92	MEC34025_ARNOLD_ARNOLTIFFI34_1_1
ALW34003_ARNOLD_ARNOLVINTO16_1_1	MEC34032_ROCK_CK_TR21_TR21
ALW34003_DUNDEE_TR94_TR94	MEC34033_SALEM3_TR21_TR21
ALW34003_HAZLTON_HAZLTDUNDE 16_1_1	MEC34X04_SALEM3_TR2 1_TR21
ALW3403G_ARNOLD_ARNOLVINT016_1_1	MECALW04_WSHEFFLD_WSHEFEMERY 16_1_1
ALW3403G_LIME_CK_LIME_EMERY 16_1_1	MP50X01_LAKEFLD_LAKEFFOX_L16_1_1
ALW3403G_VINTON_VINTODYSAR16_1_1	MP50X01_LIME_CK_LIME_EMERY 16_1_1
ALW3403_HAZLTON_HAZLTDUNDE16_1_1	NSP34002_HAZLTON_TR21_TR21
ALWARTIF_E_CALMS_E_CALCALAM11_1_1	NSP34002_LIME_CK_LIME_EMERY 16_1_1
ALWARTIF_HAZLTON_HAZLTDUNDE16_1_1	NSP34005_FOX_LK_FOX_LRUTLA16_1_1
ALWGEN03_ARNOLD_ARNOLTIFFI34_1_1	NSP34005_LAKEFLD_LAKEFFOX_L16_1_1
ALWGEN03_E_CALMS_E_CALCALAM11_1_1	NSP34005_LAKEFLD_LAKEFHERON16_1_1
ALWGEN03_E_CALMS_TR9 1_TR91	NSP34005_LIME_CK_LIME_EMERY 16_1_1
ALWGEN07_MCBW_IP-MCBW-1_A	NSP3405G_LIME_CK_LIME_EMERY 16_1_1
ALWMEC08_HAZLTON_HAZLTDUNDE16_1_1	NSP3406_LIME_CK_LIME_EMERY 16_1_1
ALWMEC13_HAZLTON_HAZLTBLKHA16_1_1	NSP34X1G_LAKEFLD_LAKEFFOX_L16_1 _1
ALWMEC16_HAZLTON_HAZLTBLKHA16_1_1	NSP50004_LAKEFLD_LAKEFFOX_L16_1 _1
ALWMEC16_HAZLTON_HAZLTDUNDE16_1_1	NSPALW02_FOX_LK_FOX_LRUTLA16_1 _1
ARNOLD_HAZLETONARNOLD_	NSPGEN01_LIME_CK_LIME_EMERY16_1 _1
ARNOLD_VINTON_161_FOR_DARNOLD_HAZLETON	NSPGEN02_LIME_CK_LIME_EMERY16_1 _1
BASE_FOX_LK_FOX_LRUTLA16_1_1	NSPGEN05 LIME_CK_LIME_EMERY16_1_1
BASE_HAZLTON_HAZLTDUNDE16_1_1	NSPGEN07_ARNOLD_TR21_TR21
DPCGENO 1 _LIME_CK_LIME_EMERY 16_1 _1	NSPGEN07_HAZLTON_HAZLTARNOL34_1_1
DUNDEEHAZLETON161 KVFLODYSARTWASHBURN16	NSPGEN07_LIME_CK_LIME_EMERY 16_1 _1
EMERY_LIME_CREEK_161_FLO_EMERY_FLOYD_1	SALEM_345_161_XFMR_FLO_TIFFIN_ARNOLD_3
HAZLETON_BLACKHAWK_161KV_FLO_DYSART_WA	SUB_56_DAVNPRT_ECALAMUS161 _FOR_QUAD_RO
LAKEFIELD_FOX_LK_161 _FOR_LAKEFIELD_LGS	TIFFIN_ARNOLD_345KV
LIME_CREEK_EMERY_161_FLO_ADAMS_HAZLETO	TIFFIN_ARNOLD_345KV_FLO_ARNOLD_UNIT_1
MEC34000_ARNOLD_ARNOLVINTO16_1 _1	VJNTON_DYSART_16 1_FLO_ARNOLD_HAZELTON_
MEC34012_SALEM3_TR21_TR21	

In the above 67 constraints defined in the SE_MN/N_IA/SW_WI NCA, there are 23 different Monitored Elements. Some future projects are expected to provide relief to these 23 Monitored Elements. These projects are listed in Table 3.4-6.

Table 3.4-6
Projects to Relieve SE_MN/N_IA/SW_WI NCA

Constrained Element	Potential Solutions	Expected ISD	App AB
Lakefield Jct-Fox Lake 161	The 2nd Lakefield - Fox Lk 161 kV line was in service in 2006, which adds a parallel to ME	2006	Com-pleted
Lime Creek-Emery 161	P90 (Emery-Lime Crk 161kV, Ckt 2) adds a parallel path for ME Lime Crk - Emery	6/1/2007	A
Hazelton 345/161	P1288 (Replace Hazleton 345/161 kV transformer #1 with 335 MVA unit) will increase ME limit	6/1/2009	A
Salem 345/161	P1287 (Replace Salem 345/161 kV transformer with 448 MVA unit) will increase ME rating	6/1/2008	A
Dundee 161/115	P1349 (Replace Dundee 161/115 kV transformer with new ratings as 112/112 MVA) will increase ME Dundee transformer limit	6/1/2011	A
Hiawatha-Dry Creek 161	P1342 (Build a new 161 kV substation Lewis Fields to be tapped to the 115 kV line Swamp Fox - Coggon at 5% distance via a new 161/115 kV transformer. Also build a new 161 kV line from Hiawatha to Lewis Fields) will provide a parallel path of ME Hiawatha - Drycreek.	6/1/2011	A
Arnold 345/161	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will close the loop of the 345 kV system, hence relieve loading on ME Arnold 345/161 kV transformer	6/1/2013	B
Arnold-Hazelton 345	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will close the loop of the 345 kV system, hence relieve loading on ME Arnold - Hazleton 345 kV line	6/1/2013	B
Arnold-Tiffin 345	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will close the loop of the 345 kV system, hence relieve loading on Arnold - Tiffin 345 kV line	6/1/2013	B
Calamus-E Calamus 161	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will relieve loading on parallel path of ME East Calamus - Calamus 115 kV line	6/1/2013	B
Davenport-E Calamus 161	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will close the loop of the 345 kV system, hence relieve loading on Davenport - E Calamus 161 line	6/1/2013	B
Hazelton-Arnold 345	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will close the loop of the 345 kV system, hence relieve loading on ME Arnold - Hazleton 345 kV line	6/1/2013	B

Constrained Element	Potential Solutions	Expected ISD	App AB
Hazelton-Dundee 161	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will relieve loading on parallel path of ME Hazleton - Dundee 161 kV line	6/1/2013	B
Lakefield Jct-Heron Lake 161	P1618 (Hrn Lk-Lkfld 161kV Ckt 1 Rbld) will increase ME limit	6/1/2013	B
Rock Creek 345/161	P1346 (Upgrade conductor inside the substation so the ratings of Rock Creek 345/161 kV transformer are 448 MVA limited by transformer) will increase ME limit	6/1/2011	B
Vinton-Dysart 161	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will relieve loading on parallel path of ME Vinton - Dysart 161 kV line.	6/1/2013	B
Arnold-Vinton 161	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will relieve loading on parallel path of ME Arnold - Vinton 161 kV line	6/1/2013	B
Calamus 161/115	P1340 (Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer) will close the loop of the 345 kV system, hence relieve loading on E Calamus 161/115 kV transformer	6/1/2013	B
Fox Lake 161/69	None		
Ipava-Macomb 138	None		
Hazelton-Blackhawk 161	None		
Fox Lake-Rutland 161	None		
Sheffield-Emery 161	None		

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Section 4.0 MTEP06 Plan Status

This section gives an update on implementation of projects approved by Board of Directors in MTEP06 and prior MTEP studies.

The Transmission Planning responsibilities of the Midwest ISO include monitoring the progress and implementation of necessary system expansions identified in the MTEP. The MISO Board of Directors approved the Midwest ISO Transmission Expansion Plan 2006 at its February, 2007 meeting. This section provides a review of the status of the approved project facilities contained in the Midwest ISO Transmission Expansion Plan 2006 listed in the Appendix A. The Midwest ISO Board of Directors has been receiving quarterly updates on the status of the active MTEP plan since December of 2005. The information in this report reflects the 2nd Quarter of 2007 status report to Board of Directors with status on MTEP 06 projects through July 31, 2007.

The purpose of tracking the progress of projects is to ensure that a good faith effort to actively move necessary projects forward towards completion is occurring, as prescribed in the Transmission Owner's agreement. Most projects that are planned and approved for construction move forward in a timely manner towards the desired in-service date. This is true despite the variety of reasons why a project may be delayed in this process, including such issues as equipment procurement delays, construction difficulties, and regulatory processes extending beyond typical lengths of time or lengths of time anticipated by the transmission Owner at the time of the original service date estimate. A project is only considered "off-track" if the Midwest ISO cannot ascertain a reasonable cause for expected project delays that include the considerations above.

MTEP 06 Appendix A contains a list projects, which have been approved by Board of Directors. These projects have completed the planning process and are the recommended solution to identified transmission system issues. These projects may be driven by reliability issues, transmission service requests, generator interconnection requests, or by either market flow constraints. A transmission system upgrade project may be comprised of multiple facilities. Over half of the projects in MTEP 06 Appendix A are comprised of multiple facilities.

Status on MTEP 06 Planned Facilities

The project facility data in MTEP 06 Appendix A was finalized in January of 2007. MTEP 06 Appendix A has 268 projects comprised of 481 facilities. The MTEP 06 Appendix A includes expansion facilities through 2011 plan year.

As a whole, 464 of the 481 or 96.5% approved facilities included in MTEP 06 are in service or moving forward towards completion at the original estimated in-service date as shown in the figure below. If we use estimated investment cost as basis for the statistic, there would be $1.952 billion out of $2.181 billion in MTEP06 Appendix A, or 89.5% of investment expected at the original in-service dates. Two of the projects that have had adjusted service dates are large projects that have an estimated combined cost of $200 million. It is important to note that the Transmission Owner of those two projects is actively working to get these projects constructed and that the adjustments of expected in-service dates were unavoidable. Additional discussion on projects with delays in implementation is below.

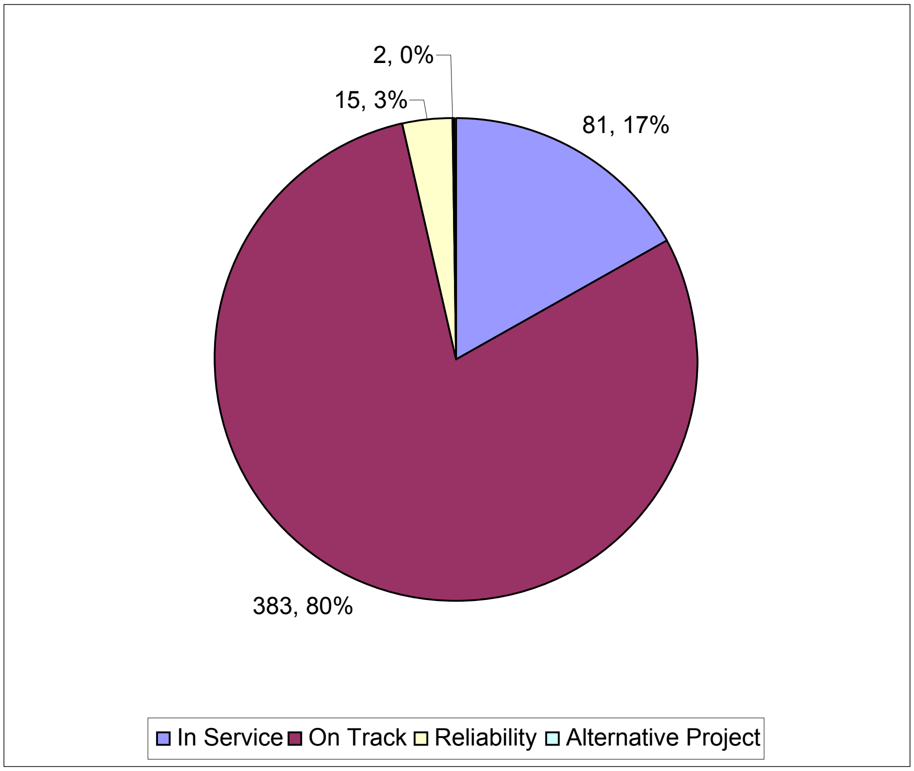

Figure 4.1-1
MTEP06 Approved Project Status

Eighty-one of the approved facilities went in service prior to summer peak load period of 2007. The following figure shows the cumulative in service progression of Appendix A facilities at the quarterly Board of Directors reports. Construction does taper off during summer peak period.

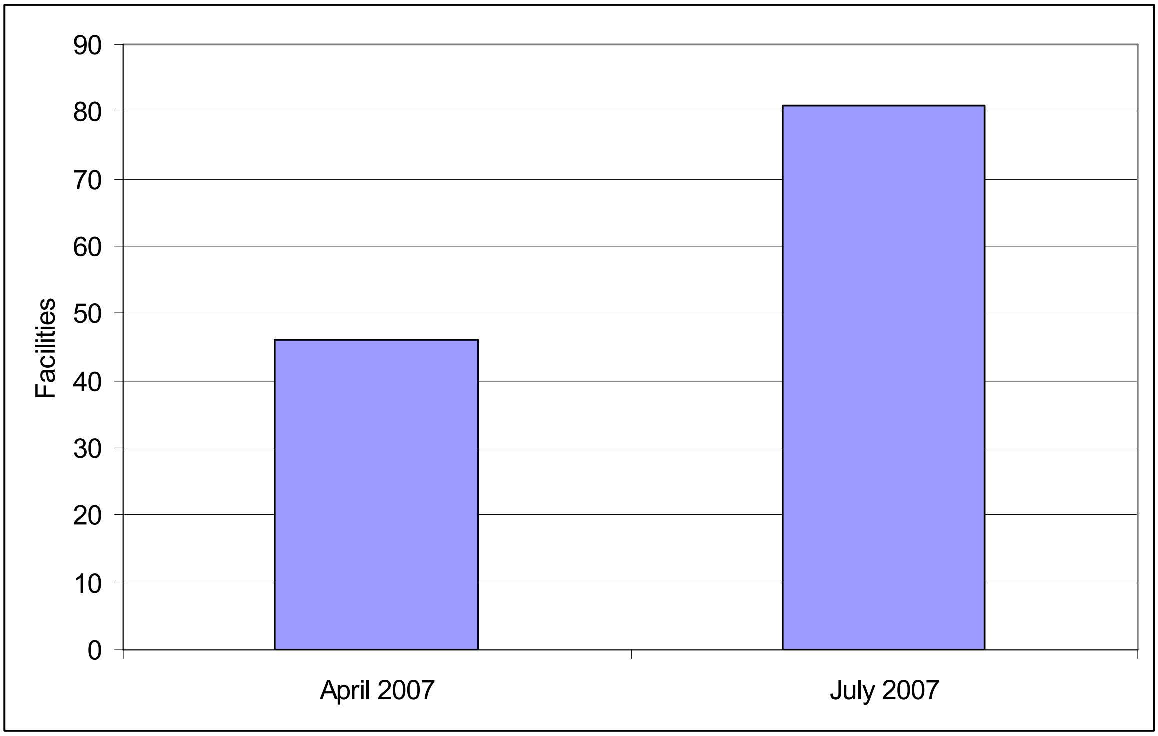

Figure 4.1-2
Cumulative Facilities In Service at Quarterly Reports

Delayed and May Impact Reliability
At the time of 2rd quarter 2007 MTEP06 status report, there were 6 of the MTEP 06 approved projects for which the need continues to exist but for unavoidable reasons have had their expected in-service sates adjusted. The Midwest ISO has documented this and will incorporate review of the critical condition driving these projects into seasonal operating reviews of the system. Seasonal operating studies include consideration of any adjustments to expected in-service dates of planned projects, and operating steps are identified as necessary to maintain reliable operation of the system. The projects are listed in the table below.

Table 4.1-3
Approved Projects with Adjusted In-Service Dates
To be Monitored in Operational Studies Until Completed

Project Description	Months Adjusted	Explanation for Adjustment
P911: Placid 345/120 transformer #2	7	Construction
P1011: Genoa-Durant 120 kV line	12	Unanticipated length of siting process
P1208: Oden 69 kV capacitor bank	17	Construction
P1488: Separate 3-terminal Prizm-Proud-Placid 120 kV line into two lines.	19	Unanticipated length of siting process
P692: Bismarck-Troy 345 kV line	19	Pre-construction regulatory authorization in progress
P907: Build Goodison Station tapping 345 kV lines, new 345/120 kV transformer, new Pontiac-Goodison 120 kV line, reterminate other 120 kV lines	19	Delay in obtaining property for substation.
P1344: Beverly 345/161 kV transformer and tap line	97	6thSt-Beverly 161kV line delays the need for the new sub. Alternative project under review.

5.0 New Appendix A Project Justifications

An important aspect of the MTEP study is review of projects by Midwest ISO staff for recommendation to Board of Directors for approval and inclusion in Appendix A. A majority of the projects moving to Appendix A in MTEP07 have been in past MTEP studies. This section describes the projects which are moving to Appendix A as part of MTEP07. Appendix A will include all previously approved projects plus those approved in MTEP07. The new projects described in this section of the report can be noted in Appendix A by the B>A or C>A designations which indicate whether they were projects from past MTEP Studies which were in Appendix B or projects new to MTEP07 which were initially in Appendix C during MTEP07.

5.1 West Planning Region

5.1.1 New Baseline Reliability Projects

Projects 277, 1022, and 1361: Badoura Projects

Transmission Owners: Minnesota Power, Great River Energy

Project Description:

These projects have gone through Minnesota regulatory review process as a single project. The project has both 115 kV and 34.5 kV transmission components. Not all of the facilities are eligible for regional cost sharing. The following components are cost shared: a new Badoura (MP) to Pine River to Pequot Lakes (MP) 115kV line (Project 277) with an estimate cost of $13.9 million. Rebuild the existing Badoura (MP) to Long Lake (GRE) 34.5kV line to 115kV with and estimated cost of $8.6 million (Project 1022).

The components of this project which are not eligible for regional cost sharing are: a new Pine River 115-34.5 kV transformer with estimated cost of $3.5 million (P277), a second Long Lake 115-34.5 kV transformer with estimated cost of $1.7 million (P1022), and Project 1361 which rebuilds the existing Badoura (MP) to Birch Lake (GRE) 34.5 kV line to 115kV and installs a Birch Lake 115-69 kV transformer with estimated cost of $9.7 million

The total 115 kV line mileage for this project is 62.7 miles. The expected in service date is May 2009 (Figure 5.1-1).

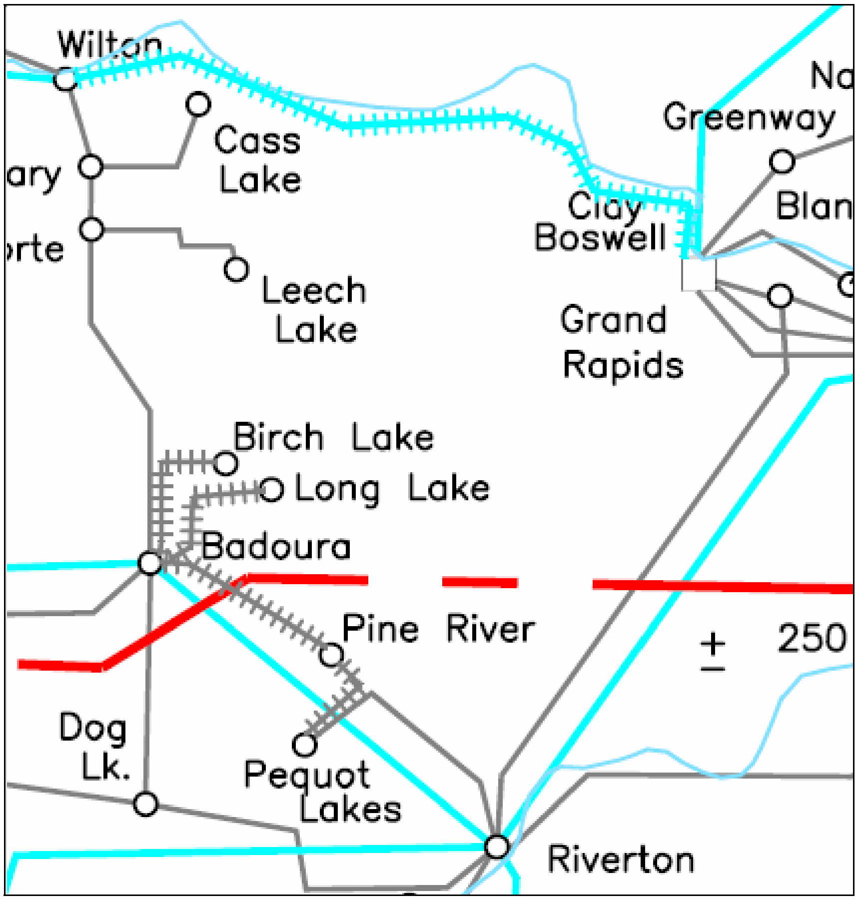

Figure 5.1-1: Geographic Transmission Map of Badoura MN Area

Project Justification:
These projects will primarily support the sub-transmission system. They also address the following Category B issues: outage of the Riverton to Merrifield 115 kV which results in very low voltage on Pequot Lakes and Merrifield 115 kV buses; and outage of the Hubbard-RDO tap 115 kV line results in low voltage 0.81 pu on RDO 7 and Long Lake 115kV buses in 2009 summer peak condition.

Project 1022 addresses the continuing economic growth in the Park Rapids and Pequot Lakes area which has caused a considerable increase in electrical use in the region. The addition of new electrical services and the increase in demand from existing services are creating electricity delivery concerns in this area. The existing electrical system, consisting of transmission lines and substations, is approaching its physical limit. Outage of a facility may result in potential long-term outages. This situation has become a concern for summer and winter peak periods, and with continued growth, the number of critical hours during the year will continue to increase.

Both Projects 277 and 1361 address the continuing addition of new electrical services and an increase in demand from existing services which are causing electricity delivery concerns along the Highway 371 corridor from Pequot Lakes to Pine River to Walker. The existing electrical system is approaching its physical limit. Outage of a facility may result in potential long-term outages. This situation has become a concern for summer and winter peak periods, and with continued growth, the number of critical hours during the year will continue to increase.

The proposed transmission system improvements will provide a second 115 kV source to the Park Rapids area, as well as a second 115 kV source into Pequot Lakes, Birch Lake and Pine River resulting in continued service to all electrical customers if one of the two 115 kV lines or transformers is out of service.

Please see Appendix D1 for West Planning Region for additional details on contingencies addressed by this project.

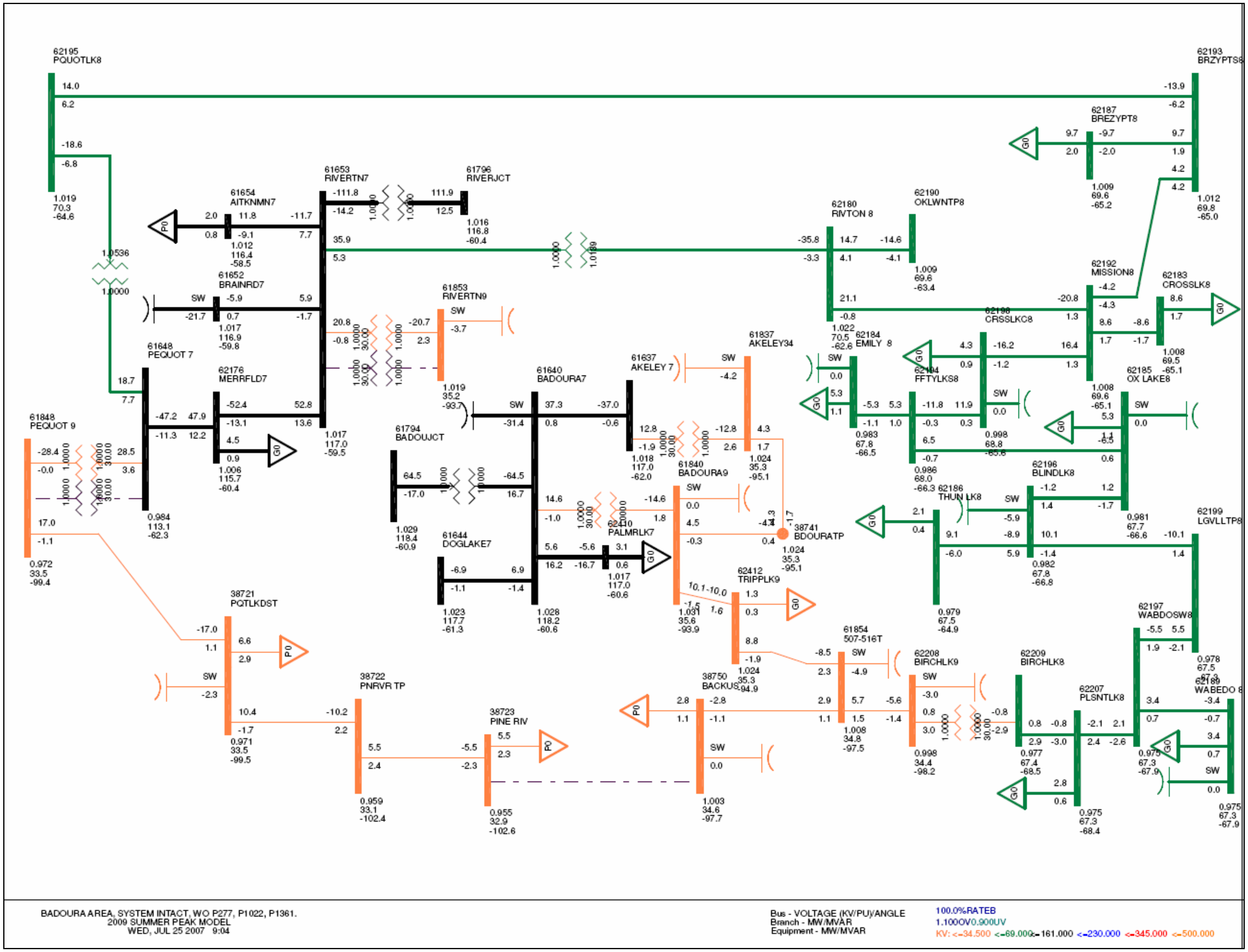

Figure 5.1-1a: Before Project System Intact 2009 Summer

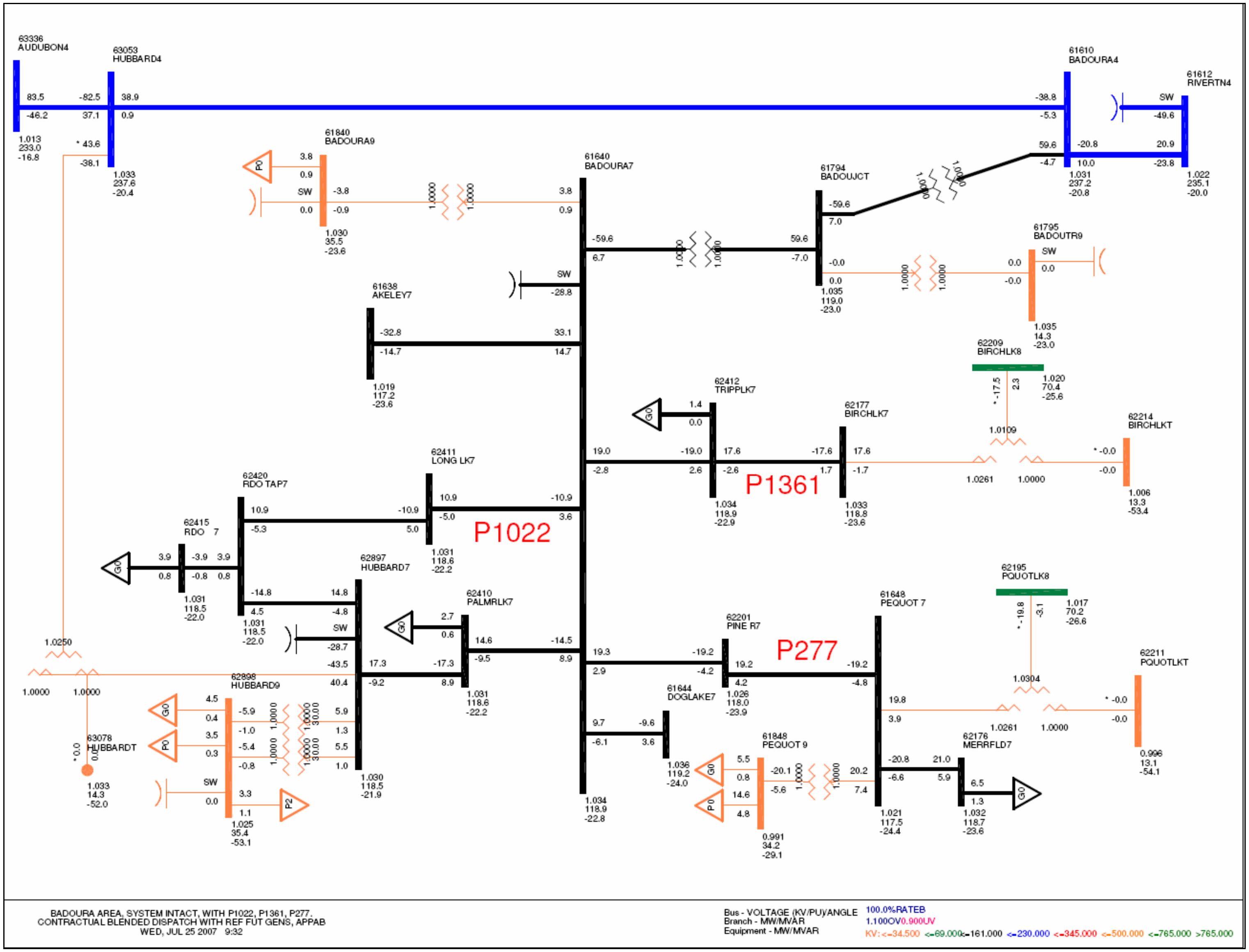

Figure 5.1-1b: With Project System Intact 2009 Summer

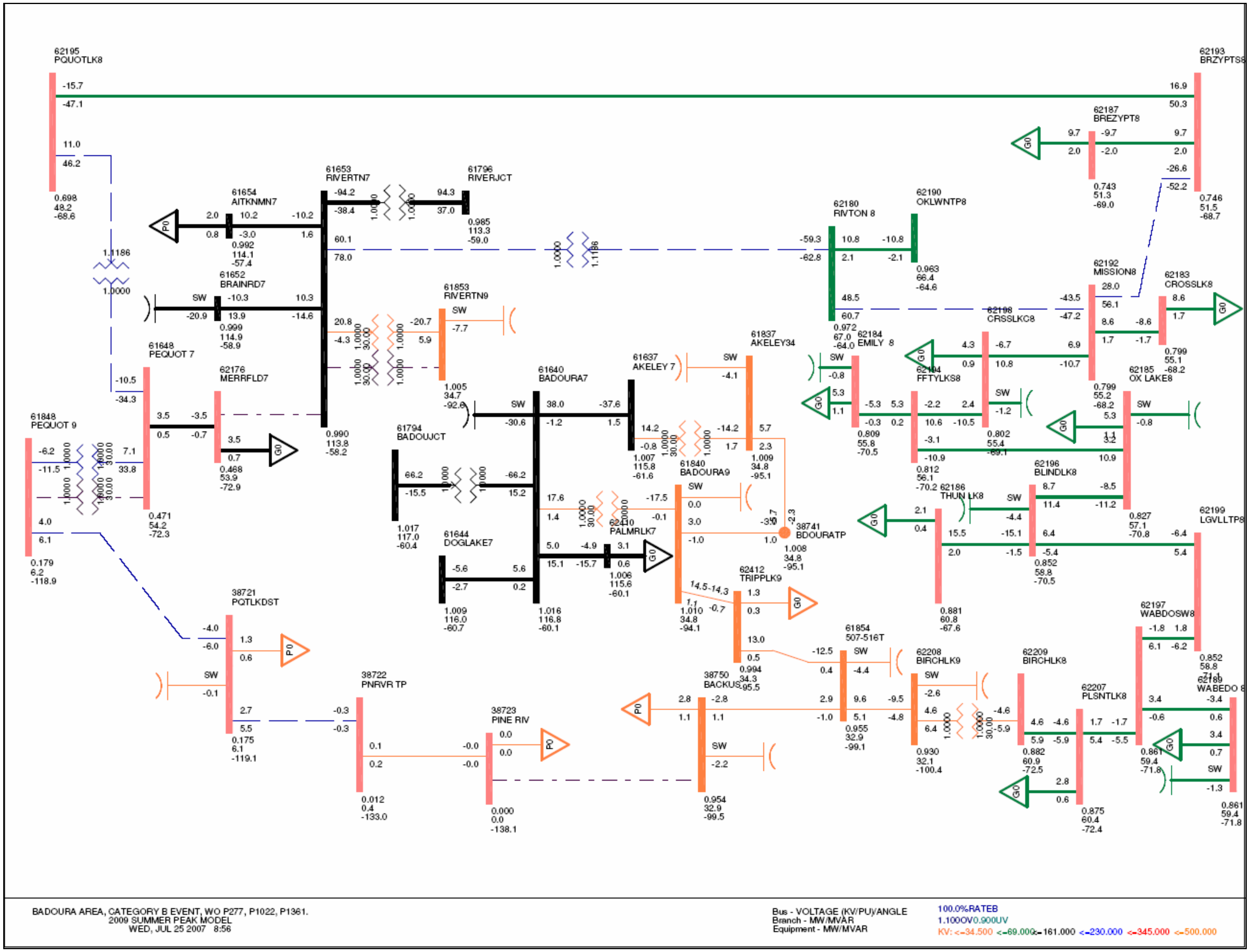

Figure 5.1-1c: Before Project Category B Contingency 2009 Summer

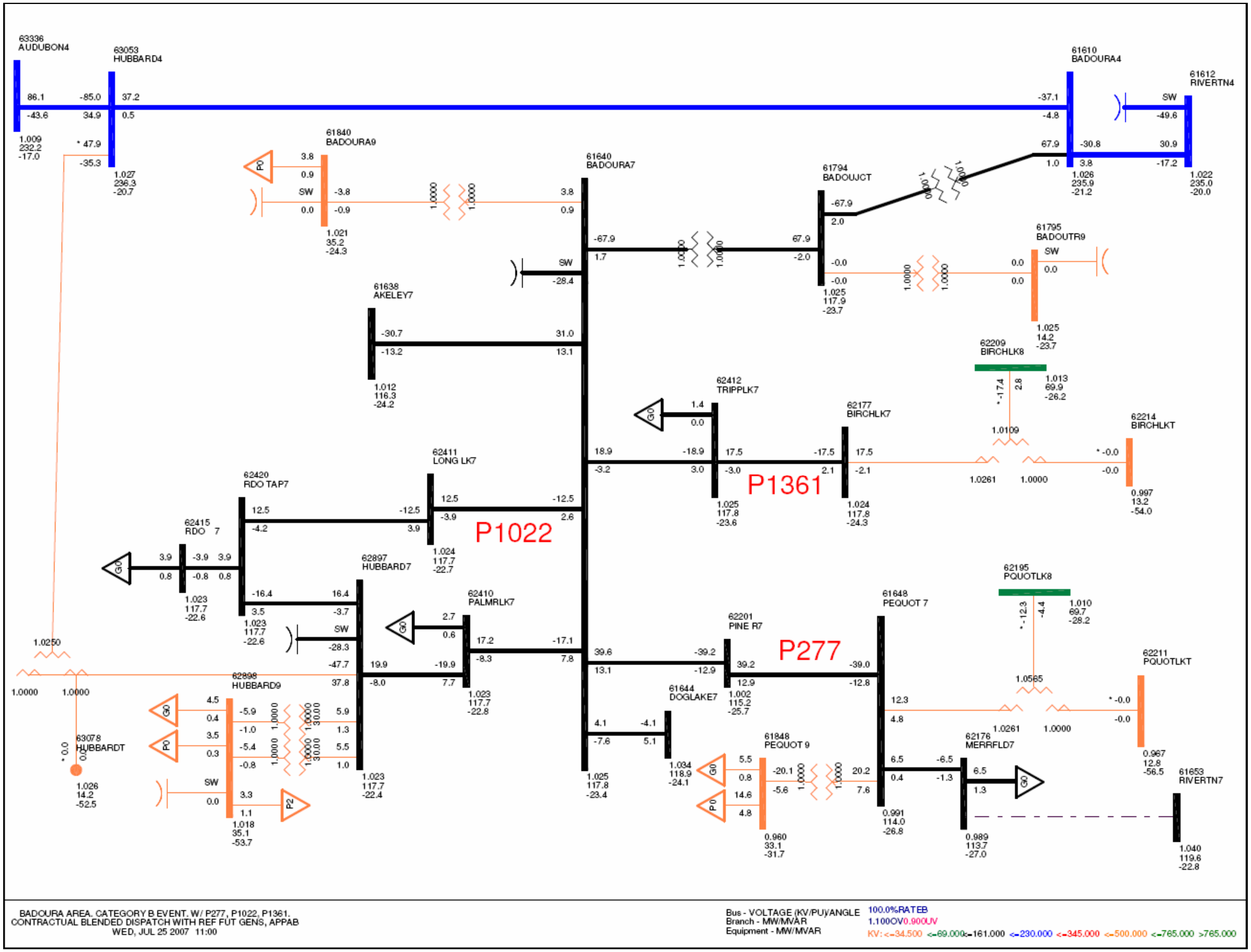

Figure 5.1-1d: With Project Category B Contingency 2009 Summer

Alternatives Considered
Several alternatives were considered but were not as reliable or as economical. The alternative of adding capacitor banks at 115 kV low voltage points doesn't address sub-transmission reliability issues adequately. Rebuilding existing facilities at existing voltages, double circuiting or reconductoring of existing lines does not provide a comparable level of electrical system performance as this 115 kV project.

Cost Allocation:
A portion of these projects are considered Baseline Reliability Projects which are eligible for regional cost sharing. The estimate cost of the project which is eligible for regional cost sharing is $22.5 million. There is no postage stamp cost allocation for this 115 kV project. The pricing zone allocations are: MP 76.34%, NSP 12.01%, OTP 11.35%, and GRE 0.29%. Appendix A1 contains cost allocation calculations.

Project 1286: Two Harbors 115 kV Switching Station and 25 Mvar Capacitor Bank

Transmission Owner: Minnesota Power

Project Description:
Construct a Two Harbors 115 kV switching station and 25 Mvar capacitor bank. This project has an estimated cost of $1.75 million. The expected in service date for this project is June 2007 (Figure 5.1-2).

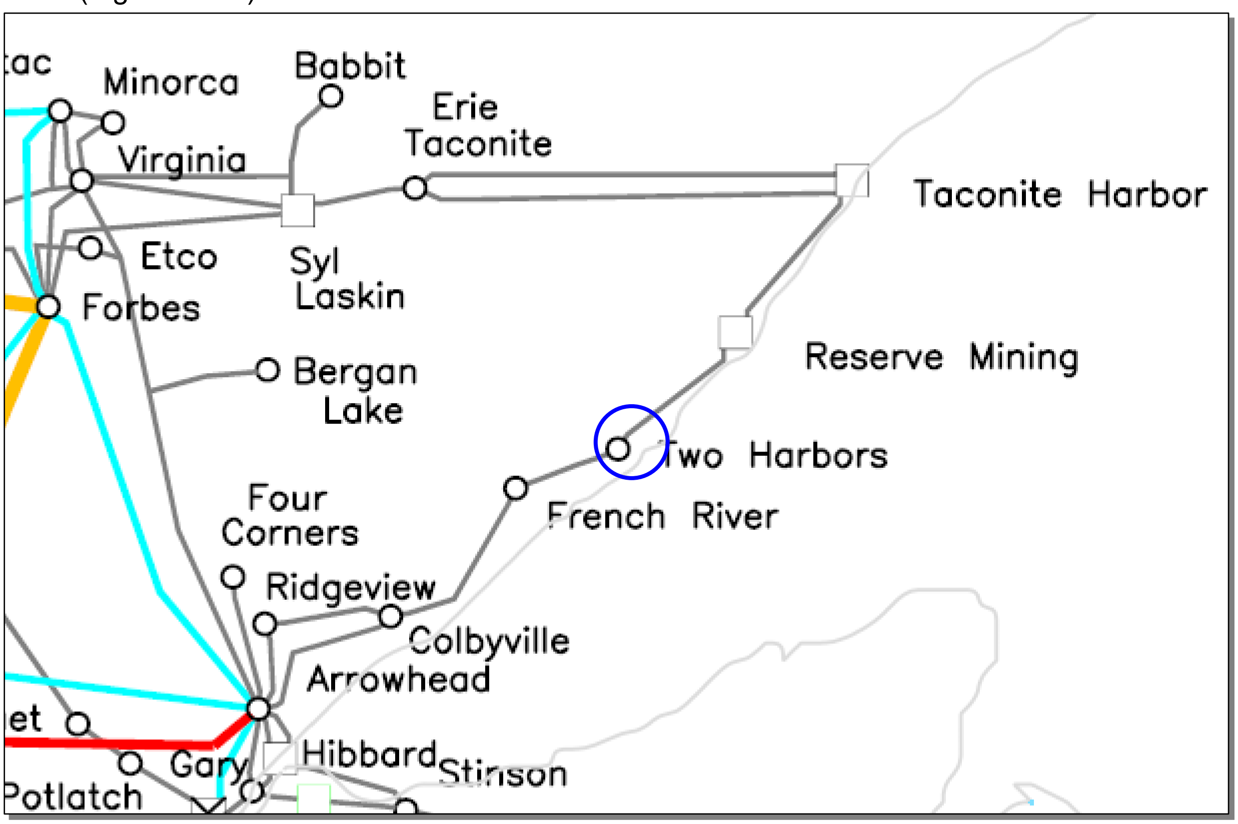

Figure 5.1-2: Geographic transmission map of Two Harbors, MN Area

Project Justification:
Under system intact (Category A), low voltage violations have been observed at French River, Two Harbors, Waldo Bank 115 kV buses. This project will provide voltage support around the area of Two Harbors, MN and enhance the system reliability.

Cost Allocation:
Project 1286 is a Baseline Reliability Project, but it is not eligible for regional cost sharing because it is under the $5 million cost threshold.

Project 882: Ontonagon 138 kV Two 8.16 Mvar Capacitor Banks

Transmission Owner: ATC LLC

Project Description:
Install two 8.16 MVar capacitor bank at Ontonagon. This project has an estimated cost of $1.2 million. The expected in service date for this project is June 2007 (Figure 5.1-3).

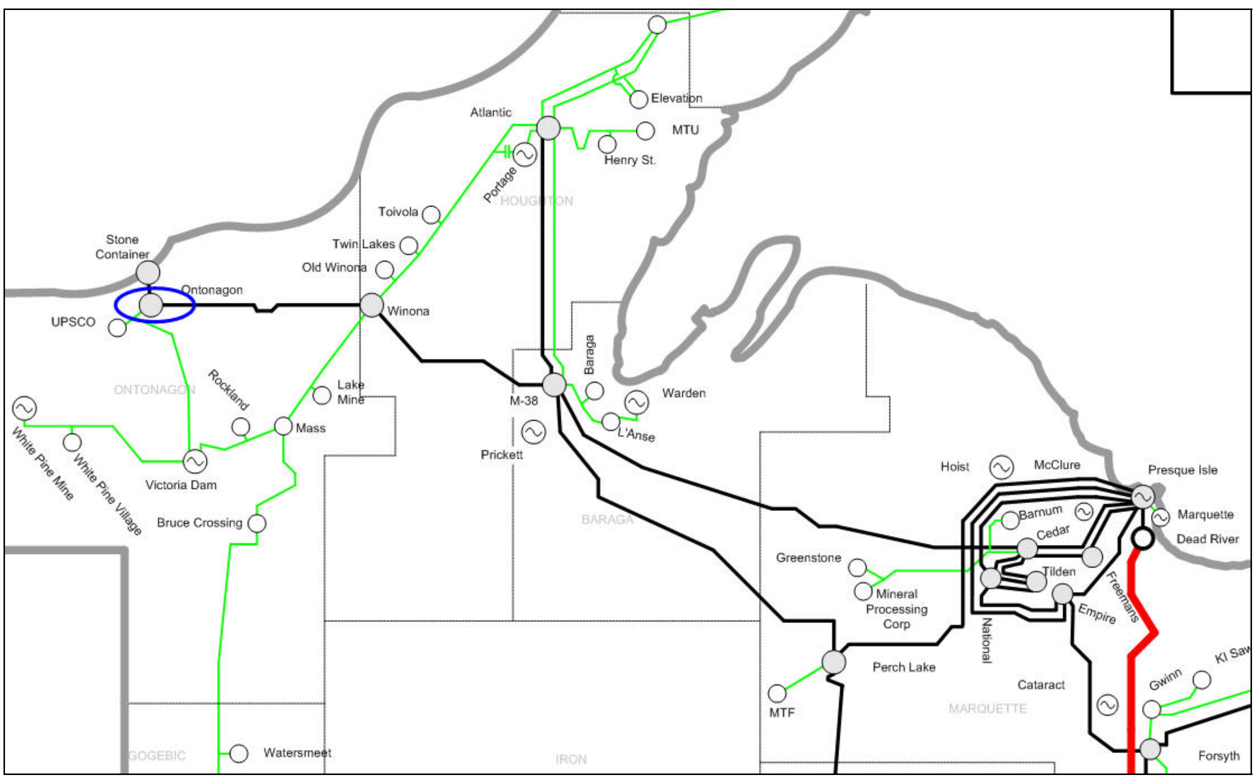

Figure 5.1-3: Geographic transmission map of Ontonagon, MI Area

Project Justification:
System normal and contingent voltages on 138 kV and 69 kV system in the northwestern Upper Peninsula of Michigan continue to be a concern. This capacitor bank installation would help to mitigate the following voltage violations especially for an outage of the Perch Lake to M38 138 kV line. The capacitor installation would help mitigate low voltages in the area for eleven

different potential contingencies. Voltages in the northwestern Upper Penninsula 138/69 kV system are low to 0.89 p.u. under system intact (Category A). Voltages at Atlantic, M-38, Winnona, Stone Container 138 kV buses may be as low as 0.82 p.u. for outage of Perch Lake – M38 138 kV line (Category B).

Cost Allocation:
Project 882 is a Baseline Reliability Project, but it is not eligible for regional cost sharing because it is under the $5 million cost threshold.

Project 1281: Uprate the Portage to Trienda X-19 138 kV Line

Transmission Owner: ATC LLC

Project Description:
Increase line clearance and replace terminal equipment for the Portage to Trienda X-19 138 kV line. This project has an estimated cost of $1.03 million. The expected in service date for this project is June 2008 (Figure 5.1-4).

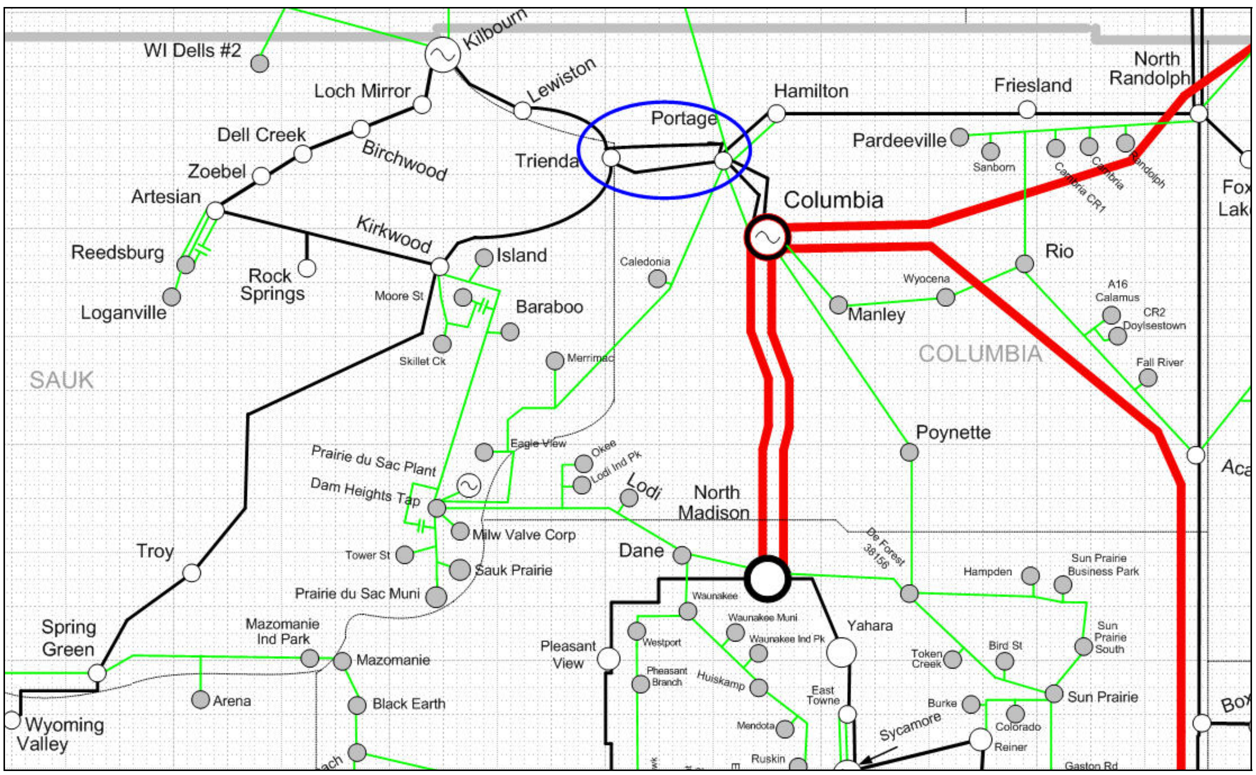

Figure 5.1-4: Geographic transmission map of Portage, WI Area

Project Justification:
This project will mitigate the Portage - Trienda 138 kV circuit #1 103% overload for outage of Portage - Trienda 138 kV circuit #2.

Cost Allocation:
Project 1281 is a Baseline Reliability Project, but it is not eligible for regional cost sharing because it is under the $5 million cost threshold.

Project 1359: International Falls 115 kV 20 Mvar Capacitor Bank

Transmission Owner: Minnesota Power

Project Description:
Install a 20 MVar capacitor bank at International Falls 115 kV substation. This project has and estimated cost of $245,000. The expected in service date for this project is June 2007 (Figure 5.1-5).

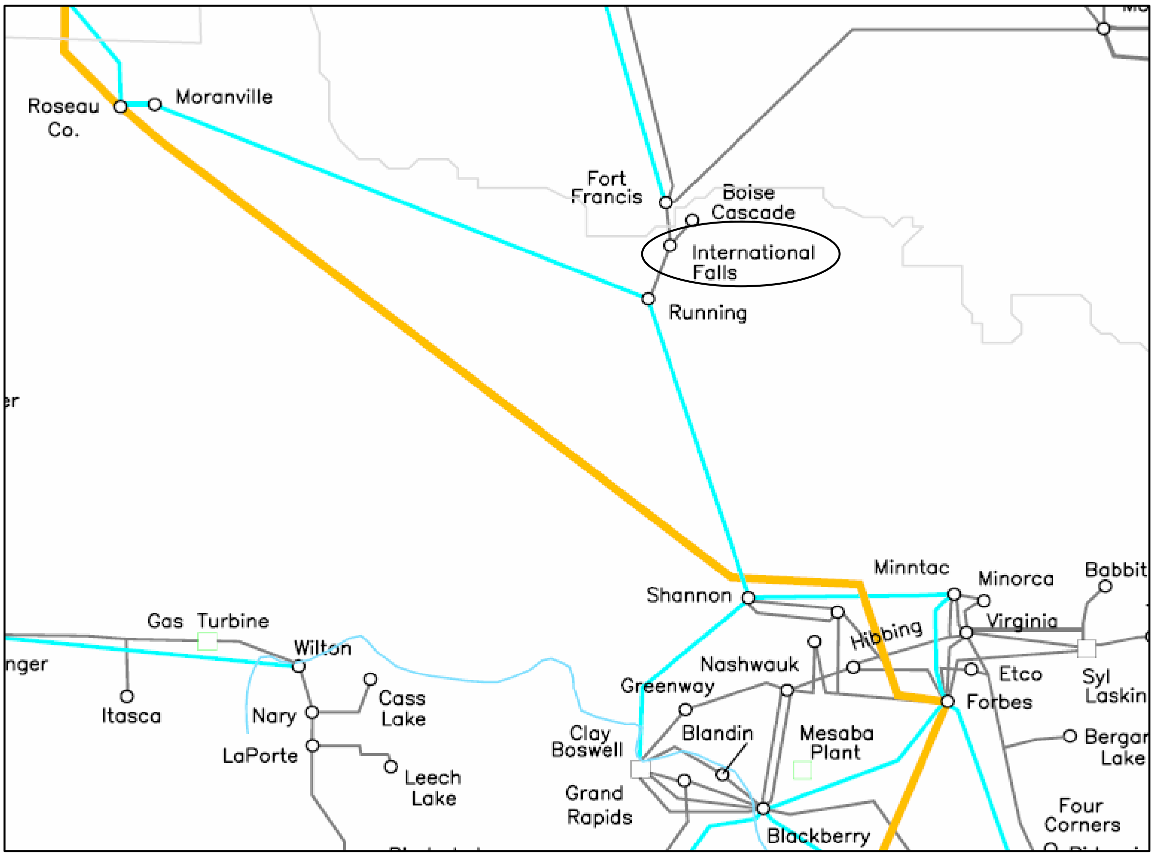

Figure 5.1-5: Geographic transmission map of International Falls, MN

Project Justification:
There are some low voltage concerns around the area of International Falls, MN. This project will provide voltage support for this area.

Cost Allocation:
Project 1359 is a Baseline Reliability Project, but it is not eligible for regional cost sharing because it is under the $5 million cost threshold.

Project 1283: Uprate Tilden - Freeman 138 kV Line

Transmission Owner: ATC LLC

Project Description:
Upgrade terminal equipment at Freeman to uprate Tilden - Freeman 138 kV Line. The estimated cost of this project is $5,000. The expected in service date for this project is June 2008 (Figure 5.1-6).

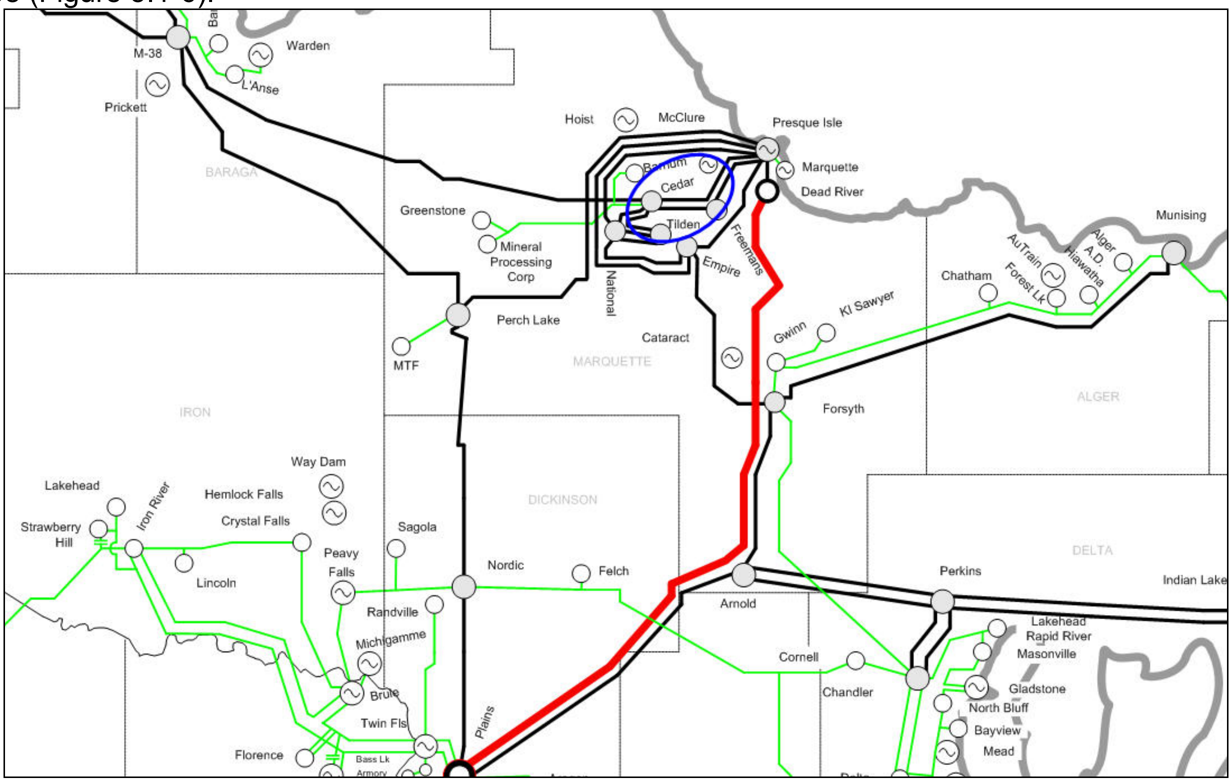

Figure 5.1-6: Geographic transmission map of Tilden-Freeman, MI

Project Justification:
This project will mitigate the Tilden - Freeman 138 kV line overload for a bus fault at National 138 kV (Category C1).

Cost Allocation:
Project 1283 is a Baseline Reliability Project, but it is not eligible for regional cost sharing because it is under the $5 million cost threshold.

5.1.2 New Generation Interconnection Projects

The following projects have Network Upgrades, therefore, they are all eligible for cost allocation per EMT. However, a majority of the projects result in 100% allocation to the Pricing Zone where the generator is located--the local pricing zone. Needs for these projects are determined by EMT governed interconnection study process. Details of these studies are posted at http://www.midwestiso.org/publish/Folder/3e2d0_106c60936d4_-76840a48324a?rev=4. Projects which have regional cost sharing will be discussed briefly below Table 5.1-1.

Table 5.1-1 Generator Interconnection Projects

PrjID	TO	Project Name	Need Summary
1541	ALTW	Network upgrades associated with 14.7 MW wind farm tapped at Jefferson Water Works 34.5 substation	GI driven. G530: 14.7 MW wind farm tapped at Jefferson Water Works 34.5 substation
1617	ATC LLC	Network upgrades associated with 280 MW coal unit at Nelson Dewey 161 kV station	GI driven. G527: 280 MW coal unit facility at Nelson Dewey 161 kV station. See below for cost sharing information.
1616	ATC LLC	Network upgrades associated with 98 MW wind farm at Cedar Ridge 138 kV substation	GI driven. G507: 98 MW wind farm AT Cedar Ridge 138 kV substation
1025	MP	Network Upgrades associated with 600 MW coal gasification generating facility at the propsoed Mesaba generating station.	GI driven. G519 : 600 MW coal gasification generating facility at the propsoed Mesaba generating station. See below for cost sharing information.
1614	XEL	Network upgrades associated with 100 MW wind farm in Osceola & Dickinson county, Iowa	GI driven. G426: 100 MW wind farm in Osceola & Dickinson county, Iowa
1613	XEL	Network upgrades associated with 100 MW wind farm interconnected at 345 kV Trimont Wind substation in Martin county, Minnesota	GI driven. G386: 100 MW wind farm interconnected at 345 kV Trimont Wind substation in Martin county, Minnesota
1542	XEL	Network upgrades associated with 19.95 MW generation tapped between Odin Tap – Odin 69 kV line	GI driven. G532: 19.95 MW generation tapped between Odin Tap – Odin 69 kV line {This is not on the Appendix A list. Confirm status}

Project 1025: G519 Mesaba Generator Interconnection

Project Description:
600 MW coal gasification plant interconnected in Minnesota Power's system requires the following transmission upgrades: Riverton 230 kV substation upgrades, Blackberry 230 kV substation upgrades, Boswell-Swatara 230 kV line 35 miles, Swatara-Riverton 230 kV line 33 miles, Swatara 230/115 kV substation. The estimated cost of the project is $76 million.

Cost Allocation:
G519 is a Generator Interconnection Project with eligible Network Upgrades. Fifty percent of Network Upgrade cost is eligible for regional cost sharing which is $38 million. The pricing zone

allocations for this project are: MP 60.55%, NSP 27.71%, OTP 8.04%, ATC LLC 2.65%, GRE 0.87%, and MDU 0.19%.

Project 1617: G527 Nelson Dewey Generator Interconnection

Project Description:
280 MW coal plant interconnected in ATC LLC's system requires the following transmission upgrades: upgrades to Nelson Dewey 161 kV substation and upgrades to Nelson Dewey-Liberty 161 kV line. The estimated cost of the project is $11 million.

Cost Allocation:
G527 is a Generator Interconnection Project with eligible Network Upgrades. Fifty percent of Network Upgrade cost is eligible for regional cost sharing which is $5,537,000. The pricing zone allocations for this project are: ATC LLC 64.17%, ALTW 29.45%, NSP 4.82%, and AmerenMO 1.55%.

5.1.3 New Transmission Delivery Service Projects

The following project is required for Transmission Delivery Service under EMT. These projects are determined via the Transmission Service Request study process. Studies to determine these projects are done via tariff defined processes. Study reports can be found at following URL http://oasis.midwestiso.org/documents/ATC/Facility Summary 75796129.pdf. These projects are not eligible for regional cost sharing.

PrjID	TO	Project Name	Need Summary
880	ATC LLC	Lost Dauphin-North Appleton-Mason Street 138 kV uprate	Transmission service request 75796129

5.1.4 New Other Projects

Other projects are typically reliability projects which serve sub-transmission which is not included in Bulk Electric System definition, therefore, Other projects are often Transmission Owner local criteria driven projects which are not eligible for cost sharing. A radial 115 kV line built to provide support to a 69 kV load area is an example of an Other type project.

Project 1021: Embarrass – Tower 115kV

Transmission Owner: Minnesota Power, Great River Energy

Project Description:
This project constructs an Embrass - Tower 115 kV 15 mile line and a new Embarrass 115/69/46 kV substation at the "34L tap" point. This project has an estimated cost of $12.2 million. The expected in service date for this project is November 2009 (Figure 5.1-7).

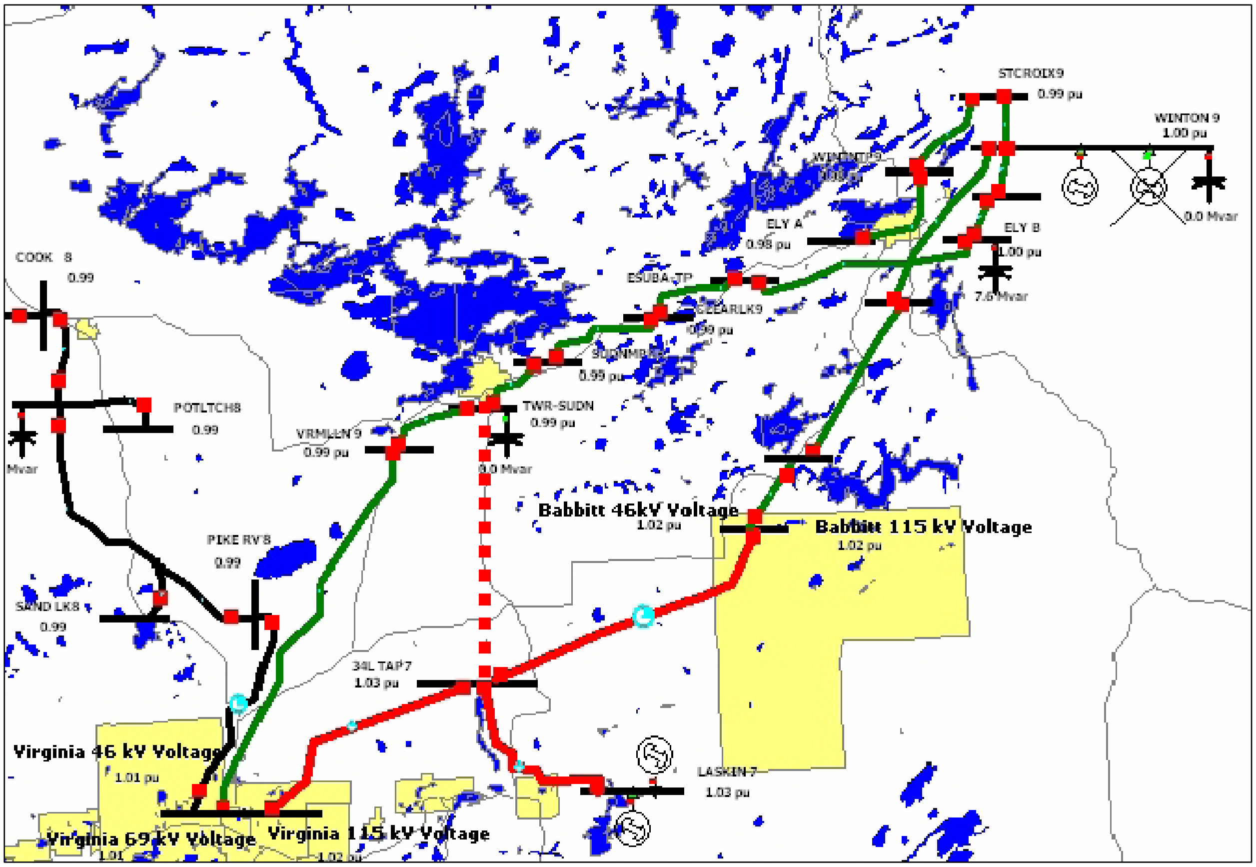

Figure 5.1-7: Geographic Transmission Map of Virginia-Babbitt 46kV Loop

Project Justification:
This project addresses 46 kV load serving issues in the MP and GRE rural areas of Vermillion, Tower, Soudan, Clear Lake, Ely, Winton, St. Croix, and Babbitt which are all currently supplied by a Virginia-Babbitt 46kV loop and the Winton hydroelectric station.

Continuing economic growth in the part of the northeastern Minnesota from Babbitt to Virginia has caused a considerable increase in electrical use in the region. The existing electrical system, consisting of transmission lines and substations, is approaching its physical limits. An outage of a facility may result in potential long-term outages. In a severe case the local transmission grid could collapse which could result in a local area blackout. This situation has become a growing concern for winter peak periods, but with continued growth, the number of critical hours during the year will continue to increase.

The following system intact conditions occur in 2009 winter peak condition:
Babbitt 115-46kV Transformer No. 1 [rated at 7.5MVA] overloads to 117%
Babbitt 115-46kV Transformer No. 2 [rated at 7.5MVA] overloads to 121%
Babbitt 31-32 TIE 46kV line [rated at 11MVA] overloads to 118%

The single contingency outage of the Babbitt - 34L Tap 115 kV line or the outage of one Babbitt 115-46kV transformer the Virginia 115-69kV transformer exceeds its 7.5MVA rating by 137%. Also, there are 16 low voltage buses (46 kV) at or below 0.92 p.u. Outage of either end of this loop will result in low voltages at the other end.

These transmission system improvements will provide a 115kV source to the Virginia-Babbitt 46 kV loop. This project has already been approved by the Minnesota Public Utilities Commission.

Alternatives Considered:
Several alternatives were considered but deemed not reliable and economical to be selected. The alternative of upgrading/rebuilding existing facilities, double circuiting and reconductoring existing lines would not provide significant improvement in reliability or security to the area.

Cost Allocation:
This is an Other project. This project is not eligible for cost sharing because it does not address Bulk Electric System (BES) issues.

Project 1267: Oak Ridge-Verona 138 kV line and Verona 138/69 kV transformer

Transmission Owner: ATC LLC

Project Description:
Construct a new 138 kV line from Oak Ridge to the existing Verona substation and install a 138/69 kV transformer at Verona. The estimated cost of this project is $17.9 million. The expected in service date for this project is June 2010 (Figure 5.1-8).

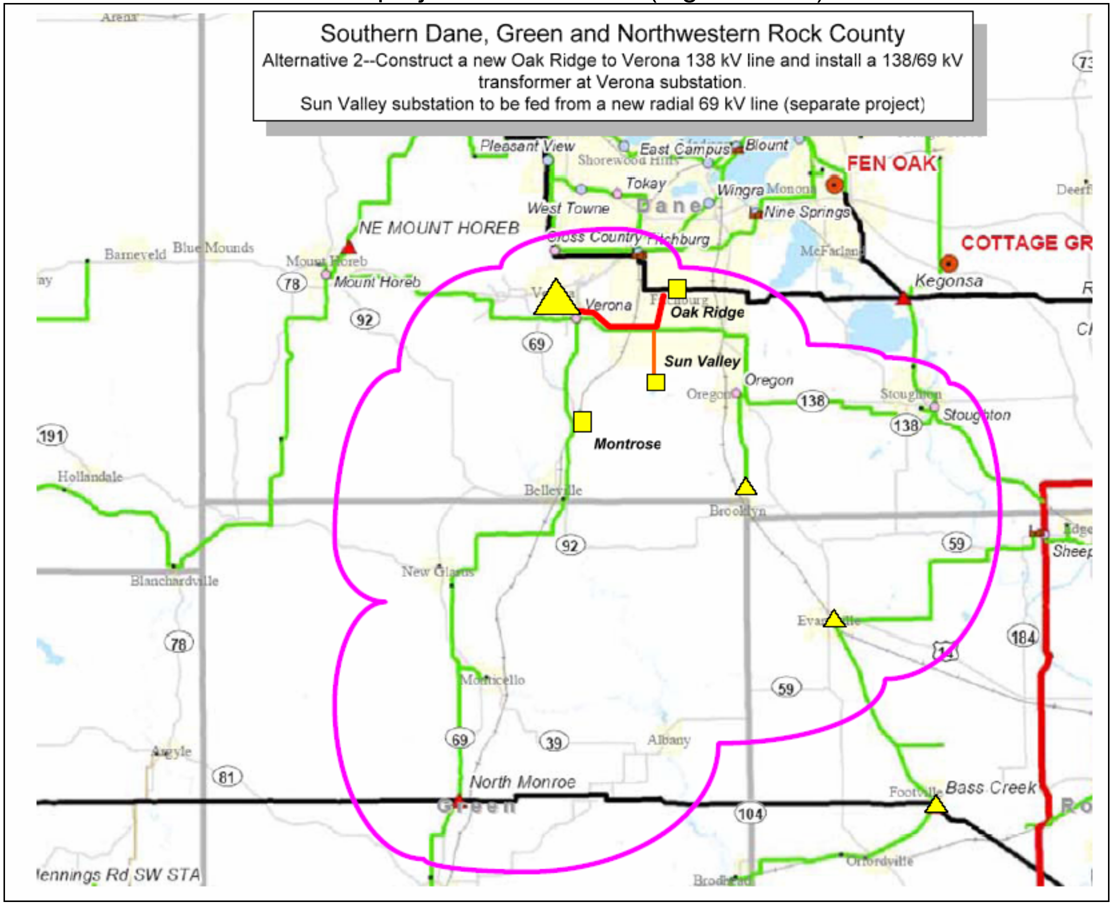

Figure 5.1-8: Geographic Transmission Map of Oak Ridge – Verona, WI

Project Justification:
This project will address reliability issues for ATC LLC 69 kV system.

The 69 kV transmission system in Southern Dane and Green Counties of Wisconsin is heavily loaded with prevailing flow of power into the area coming from the three 138/69 kV transformers at Kegonsa, North Monroe and West Middleton substations. Loads in this area are growing at nearly two times the average ATC LLC system growth rate. Additional sub-transmission system support will be required to relieve various overloads and low voltages for the outage of several key transmission facilities.

There are several Category B thermal overloads and voltage violations in 2013 summer peak period: Stoughton-Aaker Road 69 kV line overload of 140.3% for outage of North Monroe-Monticello Tap 69 kV line; Mount Horeb NE- Stoughton 69 kV line overload of 131.5% for outage of Oregon-Aaker Road (Stoughton) 69 kV line; Monticello 69 kV bus low voltage 0.709 p.u. for outage of North Monroe-Monticello Tap 69 kV line; Brooklyn 69 kV bus low voltage0.786 p.u for outage of Oregon-Aaker Road (Stoughton) 69 kV line. In order to meet the transmission system needs for the region, a new 138 kV line will be extended from Oak Ridge to the Verona substation. This will provide a new source to support the load growth in this area. See Appendix D1 for West Planning Region for detailed list of drivers for this project.

Alternatives Considered:
Alternative 1: Construct a new Evansville to Brooklyn 69 kV line and Modify Bass Creek Switching Station to install a 138/69 kV transformer. This alternative was rejected because it fails to remedy the low voltage problems in the Verona area.

Alternative 2: Construct a new 138 kV line from Fitchburg to existing Verona substation. Install a 138/69 kV transformer at Verona. This alternative was rejected because: siting and routing challenges associated with with the existing Fitchburg site; and it costs 59% more than the selected project.

Alternative 3: Construct a new Oak Ridge to Montrose (via Sun Valley) 138 kV line with 138/69 kV transformer at tnew Montrose substation. This alternative was rejected because: significant routing challenges such as public opposition, environmental concerns and poor route selection options between Sun Valley and Montrose; and most new line corridor and most costly.

Cost Allocation:
This is an Other project. The project is not eligible for cost sharing because it does not address Bulk Electric System (BES) issues.

Project 347: Rubicon-Hustiford-Hubbard 138 kV line

Transmission Owner: American Transmission Company

Project Description:
Construct a new Rubicon to Hustisford 138 kV line; rebuild Hustiford-Horicon 69 kV to 138 kV line; and install a 138/69 kV transformer at Hubbard. The estimated cost of this project is $7.2 million. The expected in service date for this project is June 2008 (Figure 5.1-9).

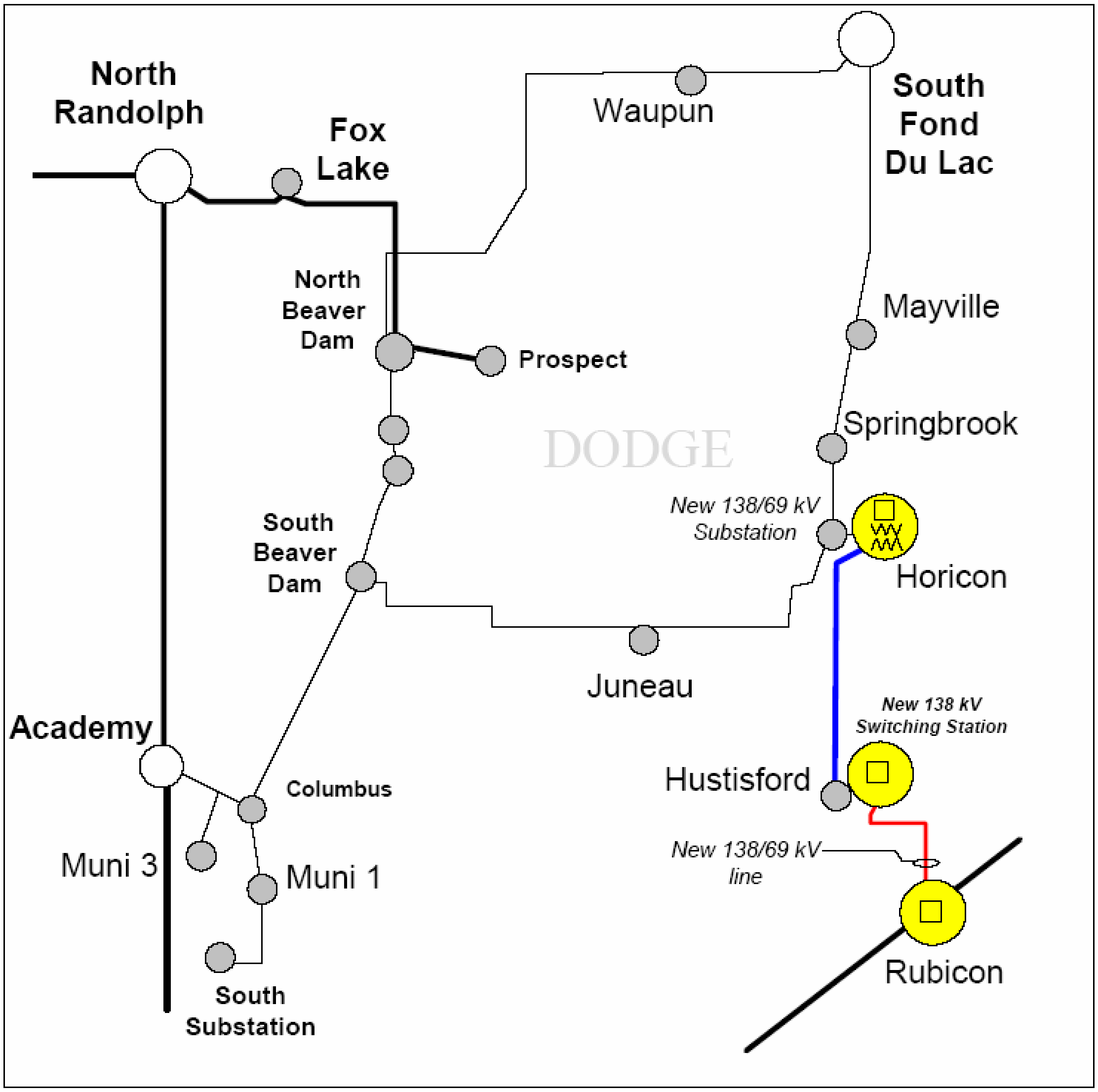

Figure 5.1-9: Geographic Transmission Map of Rubicon-Hubbard, WI

Project Justification:
This project will address reliability issues on the ATC LLC 69 kV system.

The transmission system in Dodge County, WI is heavily loaded with the prevailing power flow into the county coming from the Academy substation south of Beaver Dam, North Randolph substation north of Beaver Dam and two 69 kV lines from South Fond Du Lac substation northeast of Dodge county. This power flows are primarily on 69 kV lines that feed into the county from these three substations. As loads grow in this area, additional transmission system support will be required to relieve various overloads and low voltages for the outage of several key transmission facilities.

There are several significant thermal overloads and voltage violations in 2013 summer peak period: Juneau Tap-Horicon 69 kV line overload of 129.8% for outage of Oakfield-South Fond du Lac 69 kV line; South Beaver Dam-Juneau Tap 69 kV line overload of 108.5% for outage of Oakfield-South Fond Du Lac 69 kV line; Oakfield 69 kV bus low voltage 0.824

p.u. for outage of Oakfield-South Fond du Lac 69 kV line; and North Beaver Dam 69 kV bus low voltage 0.868 p.u. for outage of North Randolph-Fox Lake 138 kV line.

In order to meet the transmission system needs for the region, it is recommended that a new Rubicon to Hustisford 138 kV line be constructed, the existing Hustisford to Horicon 69 kV line be rebuilt and converted to 138 kV, and a new substation with a 100 MVA 138/69 kV autotransformer located near Horicon be constructed to feed the adjacent 69 kV lines.

Alternatives Considered:
Alternative 1: Conversion of Academy to South Beaver Dam line to 138 kV and New South Beaver Dam to Prospect Street line. This alternative was rejected because: 1) It fails to address the low voltage problems at Juneau and does not address overloads and maintenance problems on the South Fond du Lac to Springbrook 69 kV line.

Alternative 2: Rebuild and conversion of South Fond du Lac to Springbrook 69 kV line to 138 kV. This alternative was rejected because: 1) It does not address low voltages at Oakfield and Mayville under outage of the South Fond du Lac to Mayville/Oakfield line; 2) It is very difficult to be constructed since it would require a lengthy construction outage on the key transmission element feeding Dodge County. The risks associated with this construction outage are significant since the other three 69 kV lines feeding the area would face overloads and low voltages under the next contingency for most of the year; 3) The conversion costs at Mayville substation are estimated to be over $2 million.

Cost Allocation:
This is an Other project. The project is not eligible for cost sharing because it does not address Bulk Electric System (BES) issues.

Project 886: North Lake (Cedar) substation relocation

Transmission Owner: American Transmission Company LLC

Project Description:
Relocate the Cedar 138 kV substation to North Lake. The estimated cost of this project is $7.3 million. The expected in service date for this project is April 2009 (Figure 5.1-10).

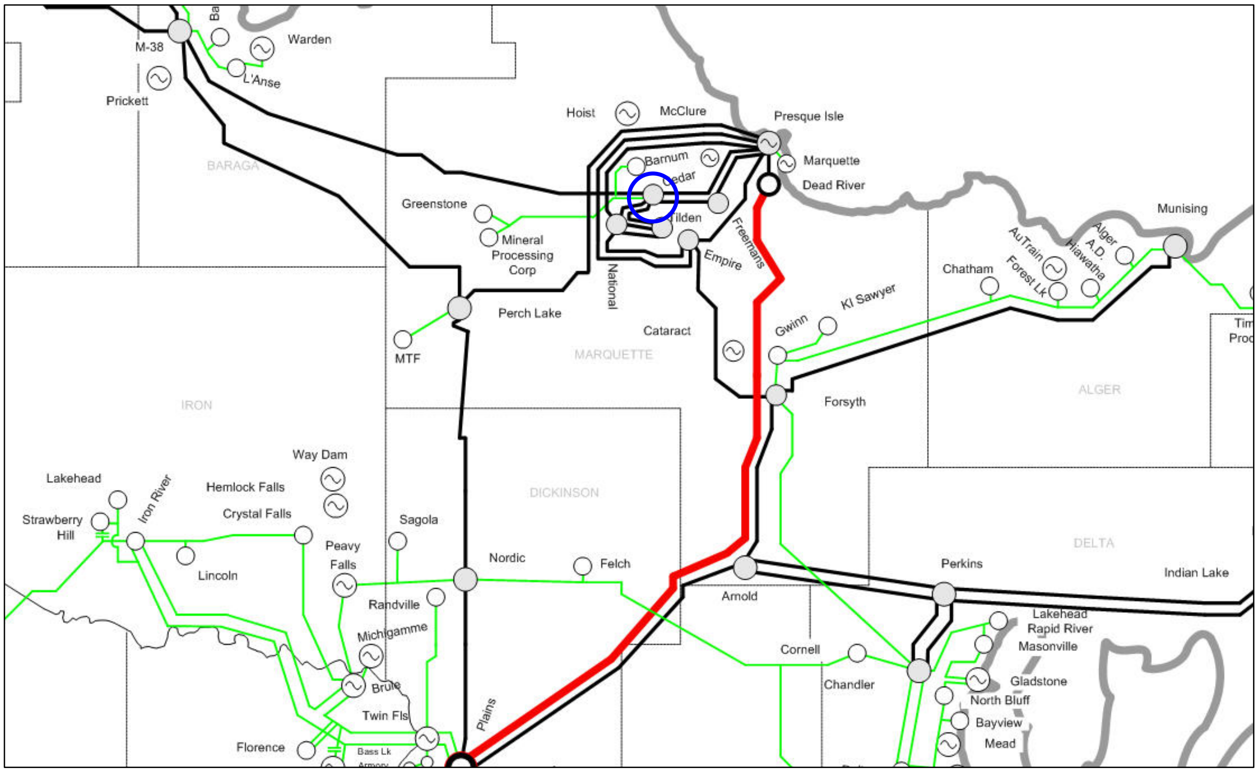

Figure 5.1-10: Geographic transmission map of Cedar Substation, MI

Project Justification:
The Cedar 138/69 kV substation located in Marquette County, Michigan is currently scheduled for a major maintenance overhaul roughly estimated to cost $3.5 million. The existing oil circuit breakers, disconnects, PTs, arrestors, bus insulators, relaying and control house are scheduled to be replaced due to condition, reliability, age and potential for certain elements to fail catastrophically due to design issues. Considering the extent of the amount of work necessary to overhaul the substation, transmission planning opted to pursue the course of constructing a new substation at a new site with the intention of improving the reliability to the area, improving maintenance flexibility and meeting the customer needs.

This project would include a new 138/69 kV substation named North Lake. This project will address equipment condition issues, increase the reliability of the transmission system, improve maintenance flexibility and meet the customers' requests.

Alternatives Considered:
The alternative of overhauling the Cedar substation was rejected because: 1) Outages of the lines and buses may be difficult to obtain and may require redispatch and load curtailment; 2) More expensive than the recommended project.

Cost Allocation:
This is an Other project with an estimated cost of $7,300,000. It is not eligible for cost sharing because it is like for like replacement.

5.2 Central Planning Region

5.2.1 New Baseline Reliability Projects

Project 152: Big River – Rockwood 138 kV line

Transmission Owner: Ameren

Project Description:
This project builds a new Big River-Rockwood 138 kV line. The estimated cost for this project is $13.4 million. The expected in service date for this project is December, 2009. Figure 5.2-1 shows the geographic transmission map of the Project 152 study area. The dashed line goes from Rockwood substation on left to the Big River substation on the right.

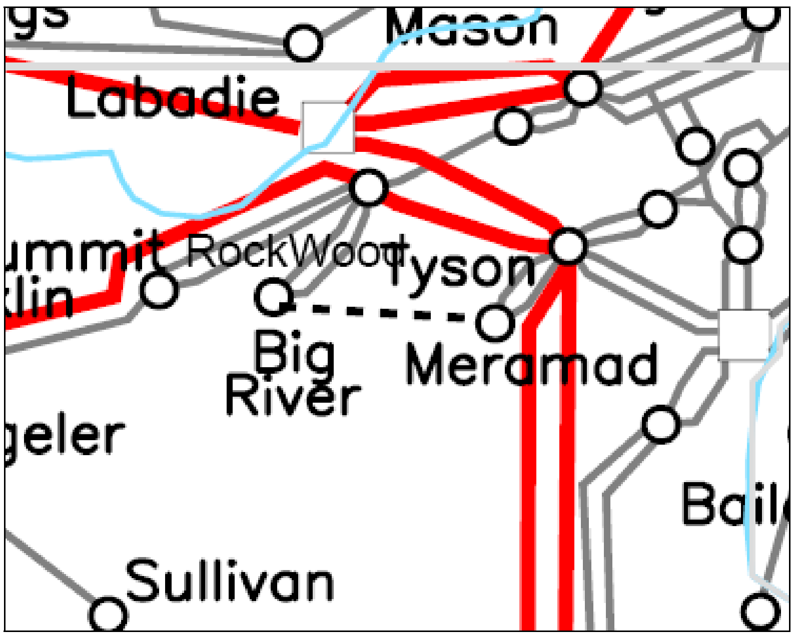

Figure 5.2-1: Geographic transmission map of project 152 study area
Rockwood is circle above Big River
Big River sub is circle below Tyson

Project Justification:
The addition of the Big River-Rockwood 138 kV line would eliminate dropping load at either Big River or Rockwood Substations for C5 double-circuit tower contingencies serving each location. These 138 kV outaged elements are presently radial distribution facilities in function, but would become networked transmission facilities with the completion of the new line.

Table 5.2-1 Project Contingency Drivers

Need Driver	Contingency	Cont type	Rat-ing (MW/ pu)	Year (load level)	Pre-Project loading/ voltage	Post-project loading/volt age
Big River 138 kV	Tyson-Big River #1 & #2	C5	1.04	2013	0	1.01
Rockwood 138 kV	Gray Summit-Rockwood 138 kV #1 & #2	C5	1.02	2013	0	1.00

Alternatives Considered:
No other transmission alternatives were considered. Load shedding Big River or Rockwood substations is an undesirable alternative. The substations have 90MW and 65MW of peak demand, respectively and increase to 120 MW and 100 MW for winter peak conditions.

Cost Allocation:
This is a Baseline Reliability Project which is eligible for regional cost sharing. The estimated cost of the project which is eligible for regional cost sharing is $13,381,000. There is no postage stamp cost allocation for this 138 kV project. The pricing zone allocations are: AmerenMO 97.76% and AmerenIL 2.24%. Appendix A1 contains cost allocation calculations.

Project 870: Sidney-Paxton 138 kV

Transmission Owner: Ameren

Project Description:
This project reconductors 18 miles of 138 kV line between Sidney and Paxton substations which has 350 kcmil copper conductor. The estimated cost of this project is $5,878,500. The expected in service date for this project is June, 2008.

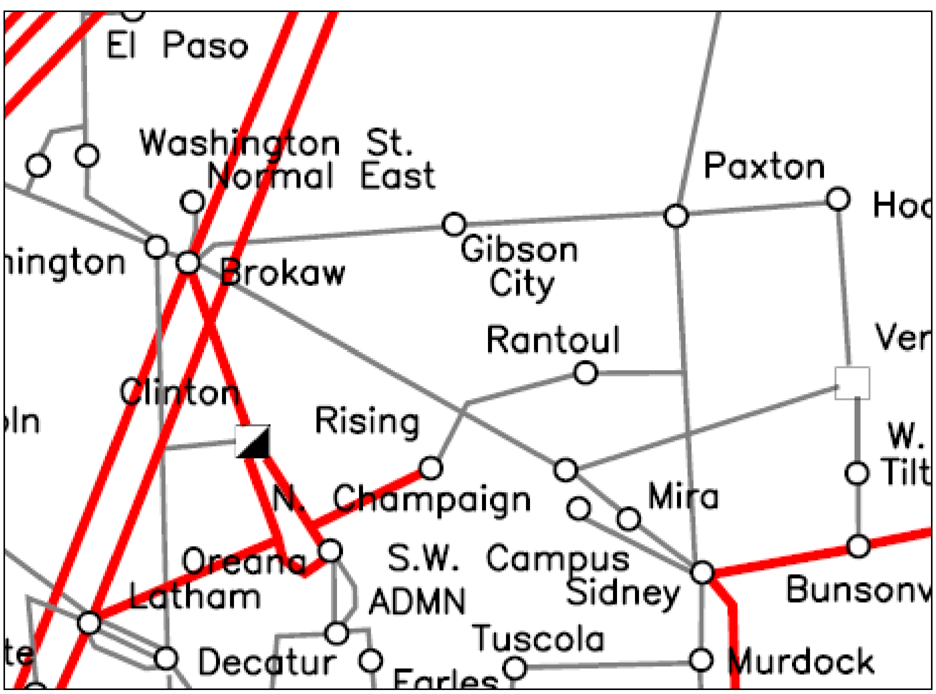

Figure 5.2-2: Geographic transmission map of project 870 study area

Project Justification:
The outage of the Sidney-Mira Tap-Perkins Road 138 kV line with Clinton generation off will load Sindey - Routal Junction - Paxton 138 kV line to above it's summer emergency rating. The existing emergency rating of the line is 174 MVA. After reconducting, the summer emergency rating will be 287 MVA. The following table shows the loading on Sidney – Rantoul section of Sidney – Paxton 138 kV line for the outaqe of Sidney – Mira Tap 138 kV line section when Clinton generation is not dispatched. The contingent overload is shown in table below.

Table 5.2-2 Project Contingency Driver

Need Driver	Contingency	Cont type	Rating (MW)	Year (load level)	Pre-Project loading	Post-project loading
Sidney-Routal Jct 138 kV	Clinton gen off + Sidney-Mira Tap	C3	174	2013	112.2%	68%

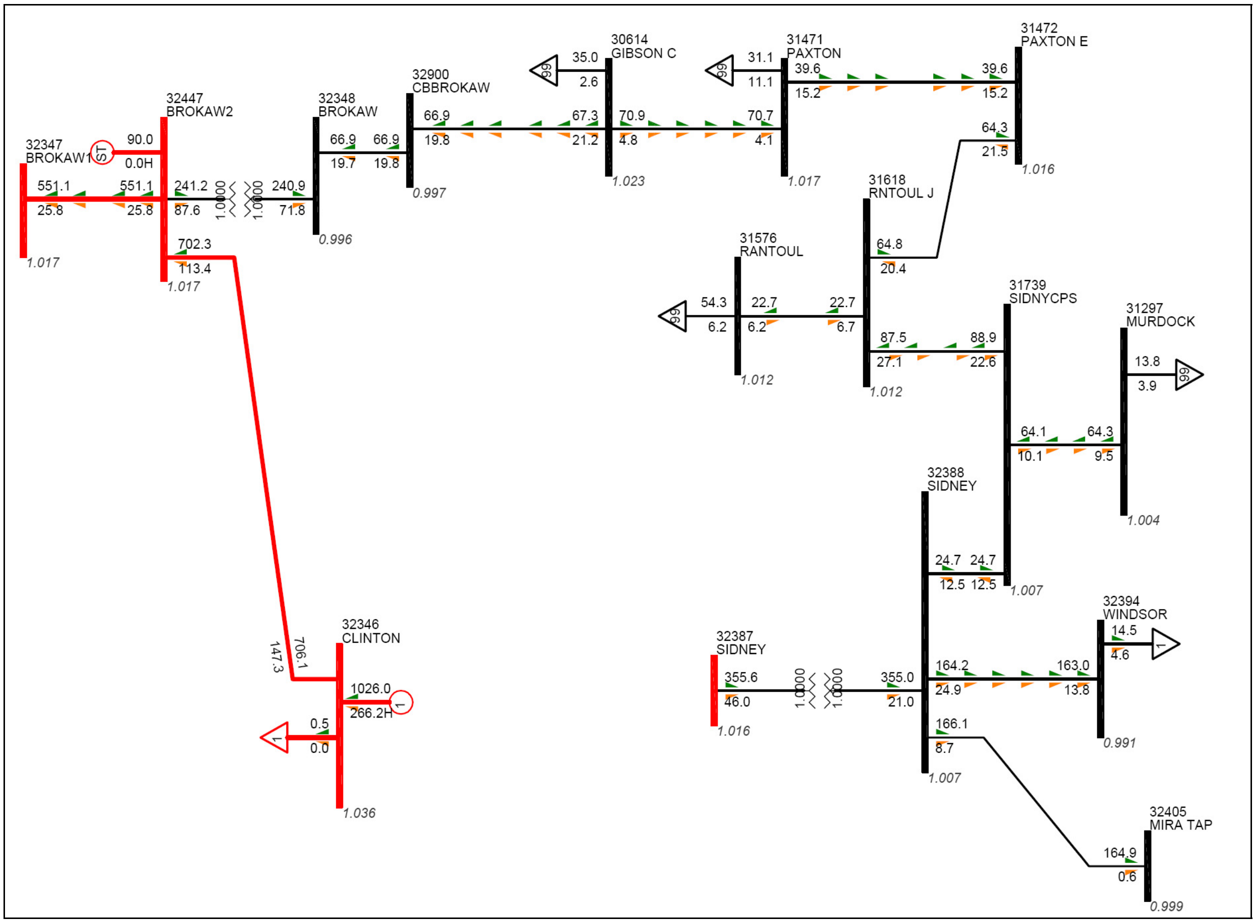

Figure 5.2-3: Project 870 study area system intact 2013

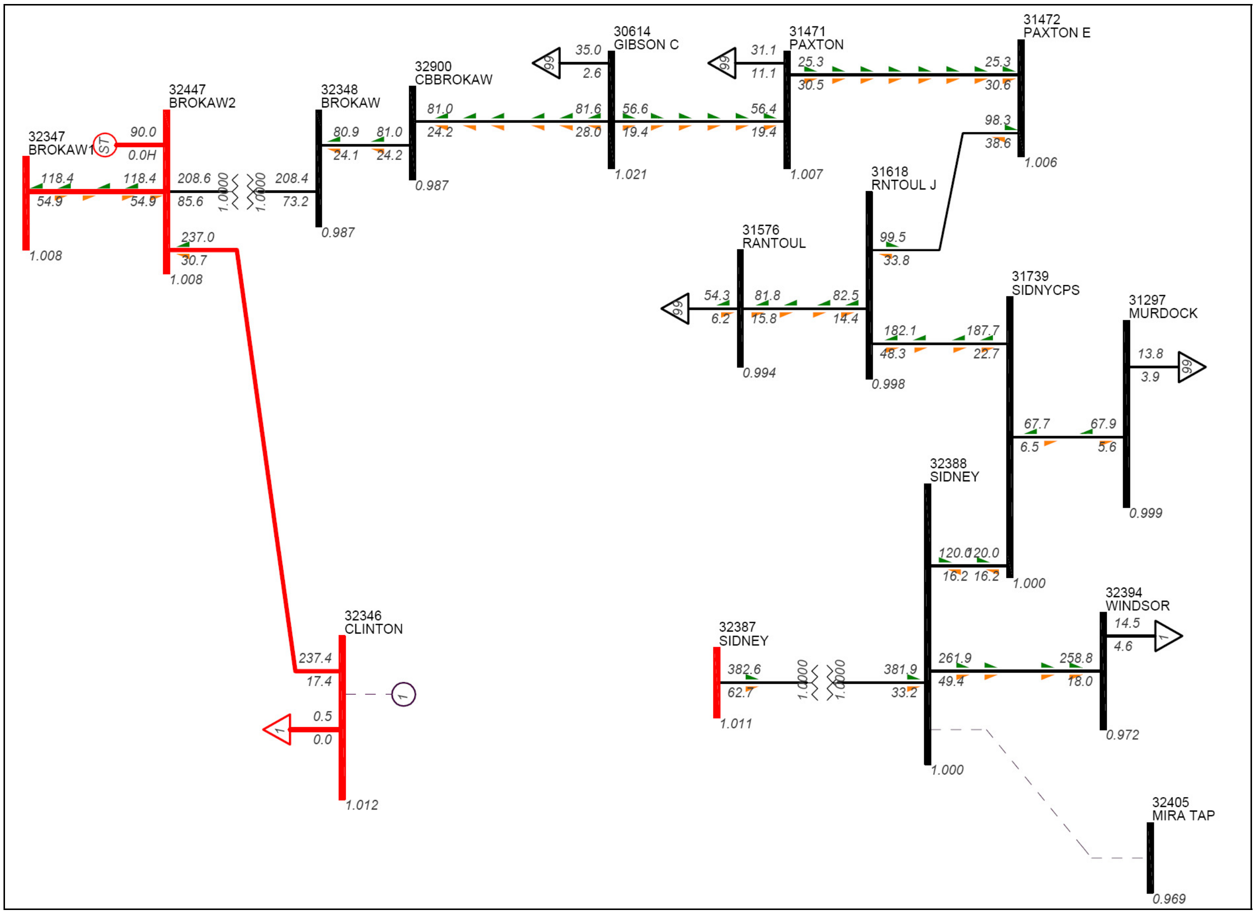

Figure 5.2-4: Project 870 study area with critical contingency 2013

Alternatives Considered:
Some of the alternatives considered for this project were the redispatch of Goose Creek and/or Gibson City generation, but the re-dispatch option was ineffective in reducing the loading on the Sidney- Rantoul 138 kV line section. The other alternative considered was to drop load, which is considered as not a preferred solution.

Cost Allocation:
This is a Baseline Reliability Project which is eligible for regional cost sharing. The estimated cost of the project that would be eligible for regional cost sharing is $5,878,500. There is no postage stamp cost allocation for this 138 kV project. The pricing zone allocations are: AmerenIL 93.14%, NIPSCO 3.44%, and Cinergy (Duke Energy Midwest) 3.43%. Appendix A1 contains cost allocation calculations.

Project 852: Crawfordsville to Tipmont Concord to Lafayette SE 138 Reconductor

Transmission Owner: Duke Energy Midwest

Project Description:
Reconductor Crawfordsville - Tipmont Concord - Lafayette SE 138 kV line. Twenty miles of the 13819 circuit will be reconductored to 954 ACSR conductor with an emergency rating of

307 MVA. The estimated cost of the project is $8.57 million. The expected in service date is December 2009.

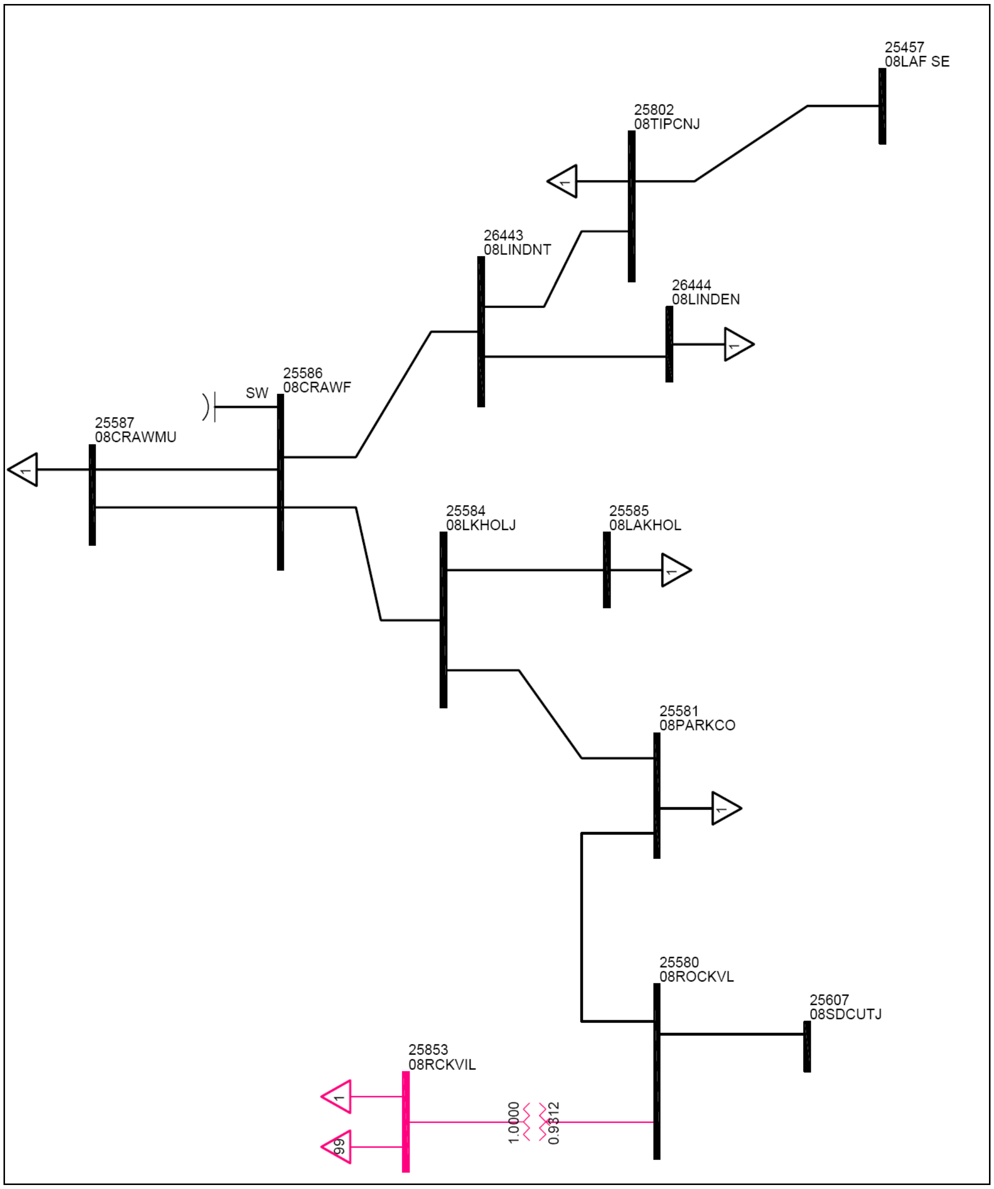

Figure 5.2-5: Transmission map of Project 852 study area

Project Justification:
Twenty miles of the Crawfordsville - Tipmont Concord - Lafayette SE 138 kV (13819) line currently has 4/0 copper conductor. The ratings for this circuit use conductor temperature of 80°C for Copper and 100°C for aluminum. The 13819 circuit has an emergency rating of 120 MVA. Outage of 13846 Rockville to Parke Co. Marshall 138 kV line causes 100% loading on 13819 circuit. This is a Category B event. Reconductoring is recommended.

Table 5.2-3 Project Contingency Drivers

Need Driver	Contingency	Cont type	Rating(MW /pu)	Year (load level)	Pre-Project loading/voltage	Post-project loading/voltage
Lafayette SE – Tipmont Concord 138 kV line	13846 Rockville to Park Co. Marshall	B	120	2013	100%	39%

Figure 5.2-6 is the project 852 area under system intact condition. Figure 5.2-7 shows the critical contigenency driving the project.

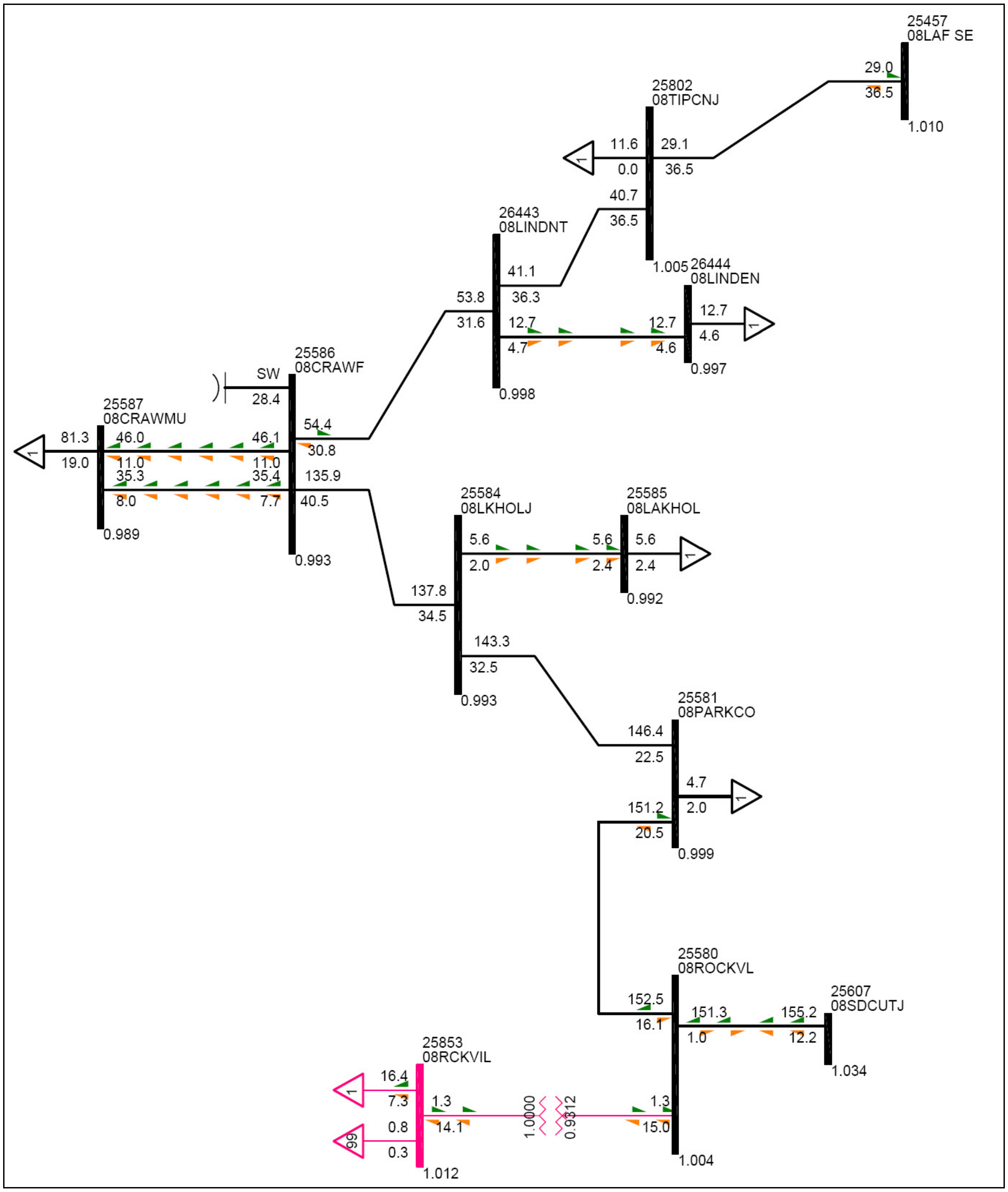

Figure 5.2-6: Project 852 study area System Intact 2013

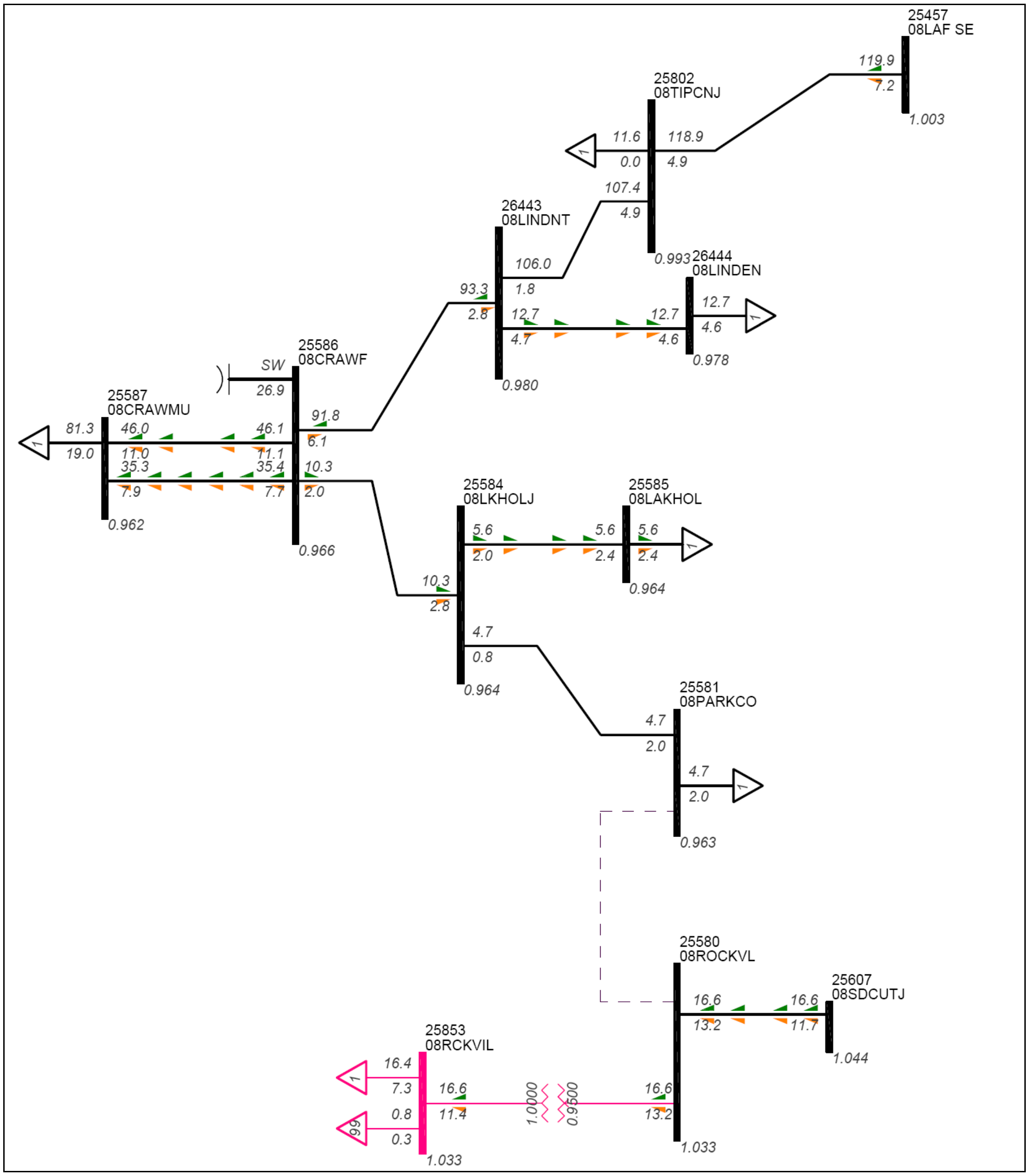

Figure 5.2-7: Project 852 study area with critical contingency 2013

Alternatives Considered:

No transmission alternatives considered. Reconductoring is the least cost option.

Cost Allocation:

This is a Baseline Reliability Project which is eligible for regional cost sharing. The estimated cost of the project which is eligible for regional cost sharing is $8.57 million. There is no postage stamp cost allocation for this 138 kV project. The pricing zone allocations are: Cinergy (Duke Energy Midwest) 99.56%, NIPSCO 0.35%, and Hoosier 0.09%. Appendix A1 contains cost allocation calculations.

Project 866: Latham 138kV Line Termination

Transmission Owner: AmerenIP

Project Description:
This project installs a new line termination with 138 kV breaker for 'in-and-out' tap to 138 kV Line 1346, which creates two 2-terminal lines from the prior 3-terminal line configuration. The project also constructs 0.38 miles 138 kV line for the 'in-and-out' connection. Figure 5.2-8 shows the geographic transmission map of the study area. The Latham substation is in circled in the lower right. Figure 5.2-9 is a detailed one-line diagram of the project. The estimated cost of this project is $1,494,400. This project was completed on May 15, 2007.

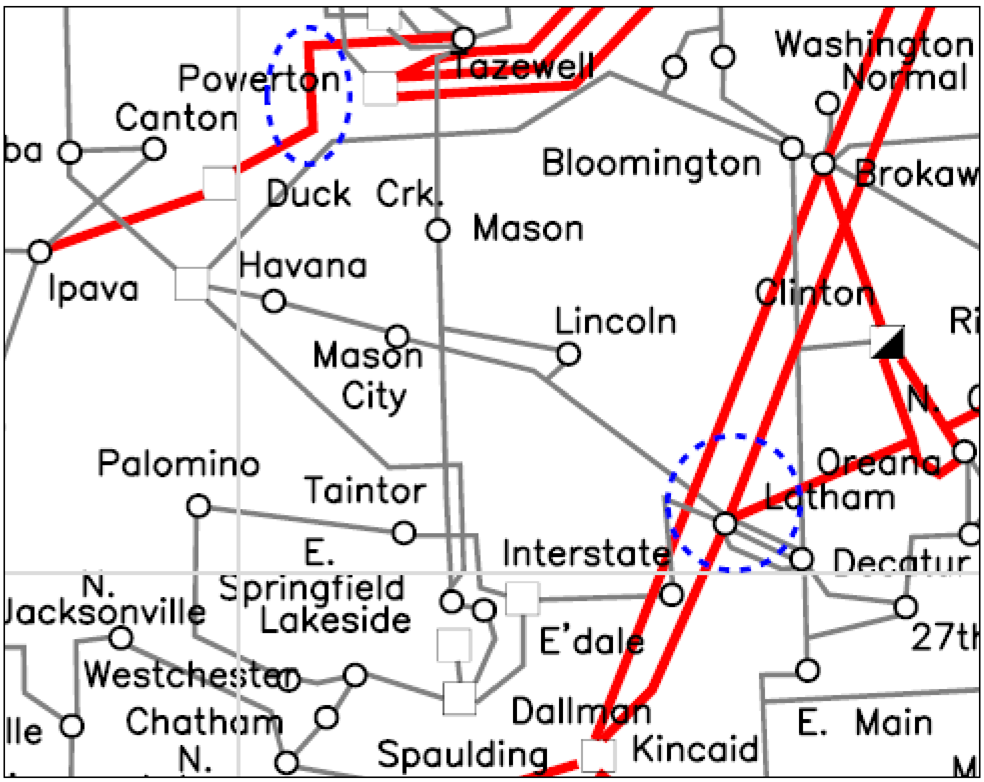

Figure 5.2-8: Geographic transmission map of project 866 study area

Project Justification:
This project would increase the rating on Mason City West – Latham 138 kV line from 137 MVA to 165 MVA. This line was identified as limit that would not allow to complete delivery of Duck Creek, Havana and Meredosia units for the outage of Duck Creek – Tazewell 345 kV line.

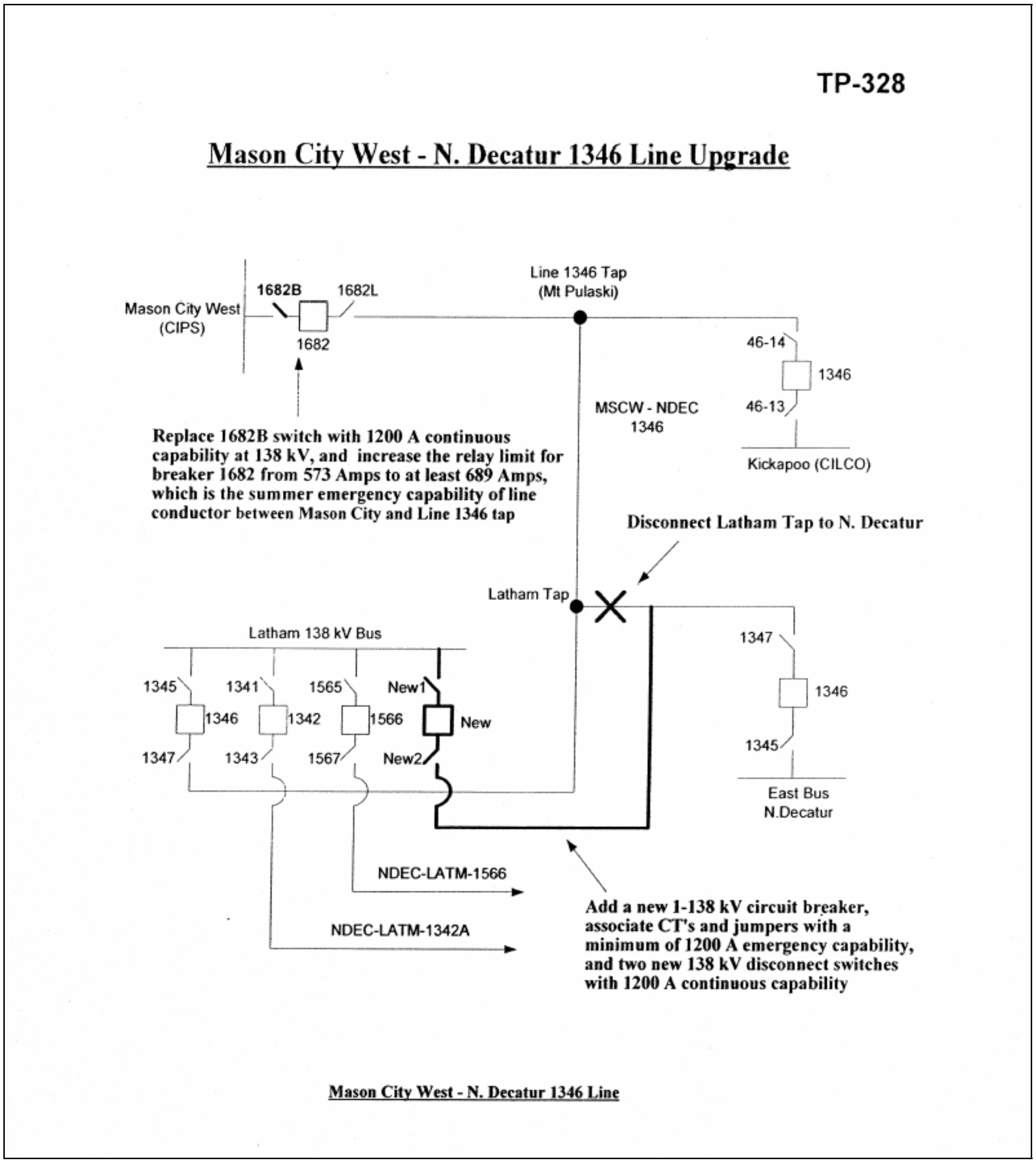

Figure 5.2-9: One line diagram of Project 866

Alternatives Considered:
None. This project is a cost effective solution.

Cost Allocation:
This is a Baseline Reliability Project which is not eligible for regional cost sharing because it is less than $5 million.

Project 783: Robinson Marathon 138kV Substation

Transmission Owner: Ameren

Project Description:
Robinson Marathon 138kV substation – Increase 18 Mvar capacitor bank to 36Mvar
The estimated project cost is $259,200. This project was completed on June 25, 2007. Figure 5.2-10 shows the geographic transmission map of the study area.

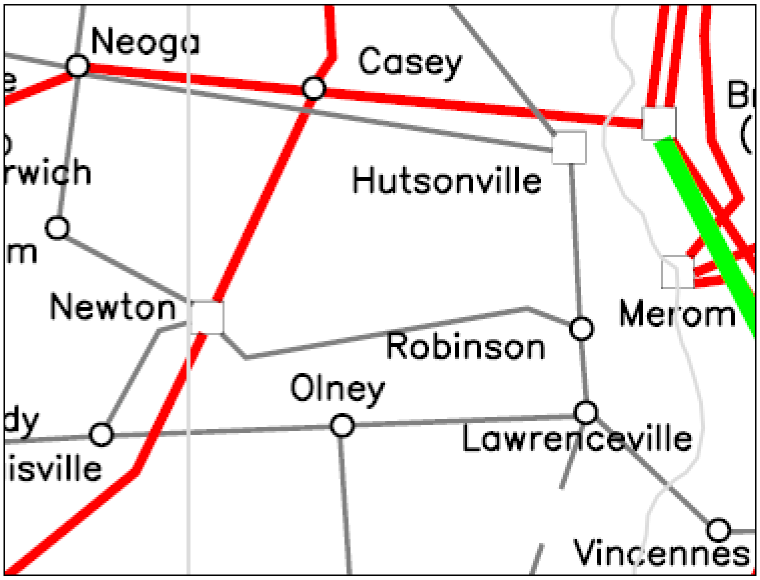

Figure 5.2-10: Geographic transmission map of project 783 study area

Project Justification:
Increase local voltage support for conditions with Hutsonville generation (unit #3 is 80MW, unit #4 is 81MW) off and the outage of the Newton-Robinson 138kV line. The category C3 outage results indicate that the voltage at Robinson Marathon 138 kV bus would drop from 100% to 93% of nominal voltage.

Table 5.2-5 Project Contingency Drivers

Need Driver	Contingency	Cont type	Rating (MW/pu)	Year (load level)	Pre-Project loading/voltage	Post-project loading/voltage
Local voltage at Robison 138kV	Hutsonville generation (30771, 80MW, 30772, 81MW) off and the outage of the Newton-Robinson 138kV line	C3	1.0012	2013	0.9184	0.9324

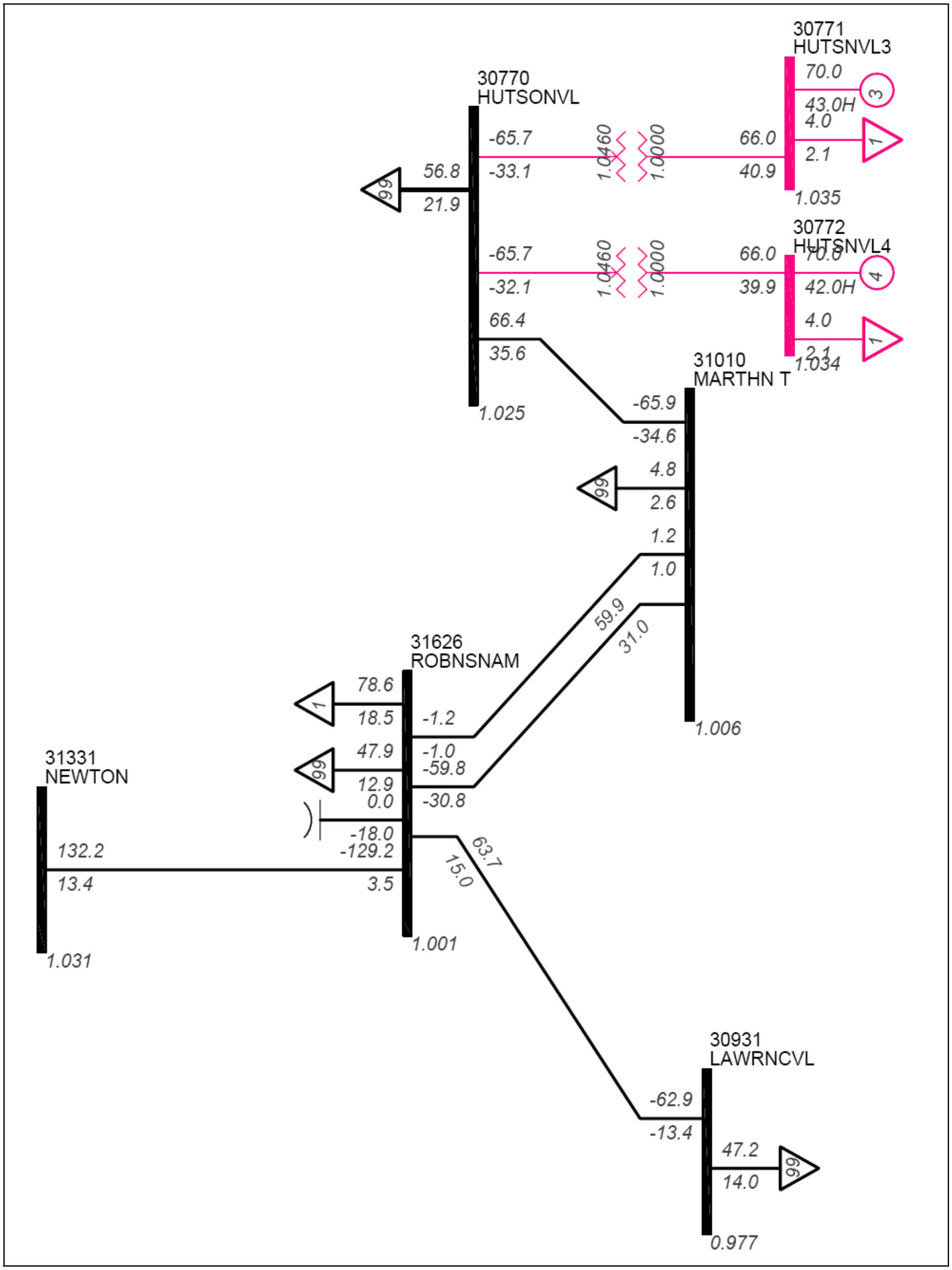

Figure 5.2-11: Project 783 study area in system intact 2013

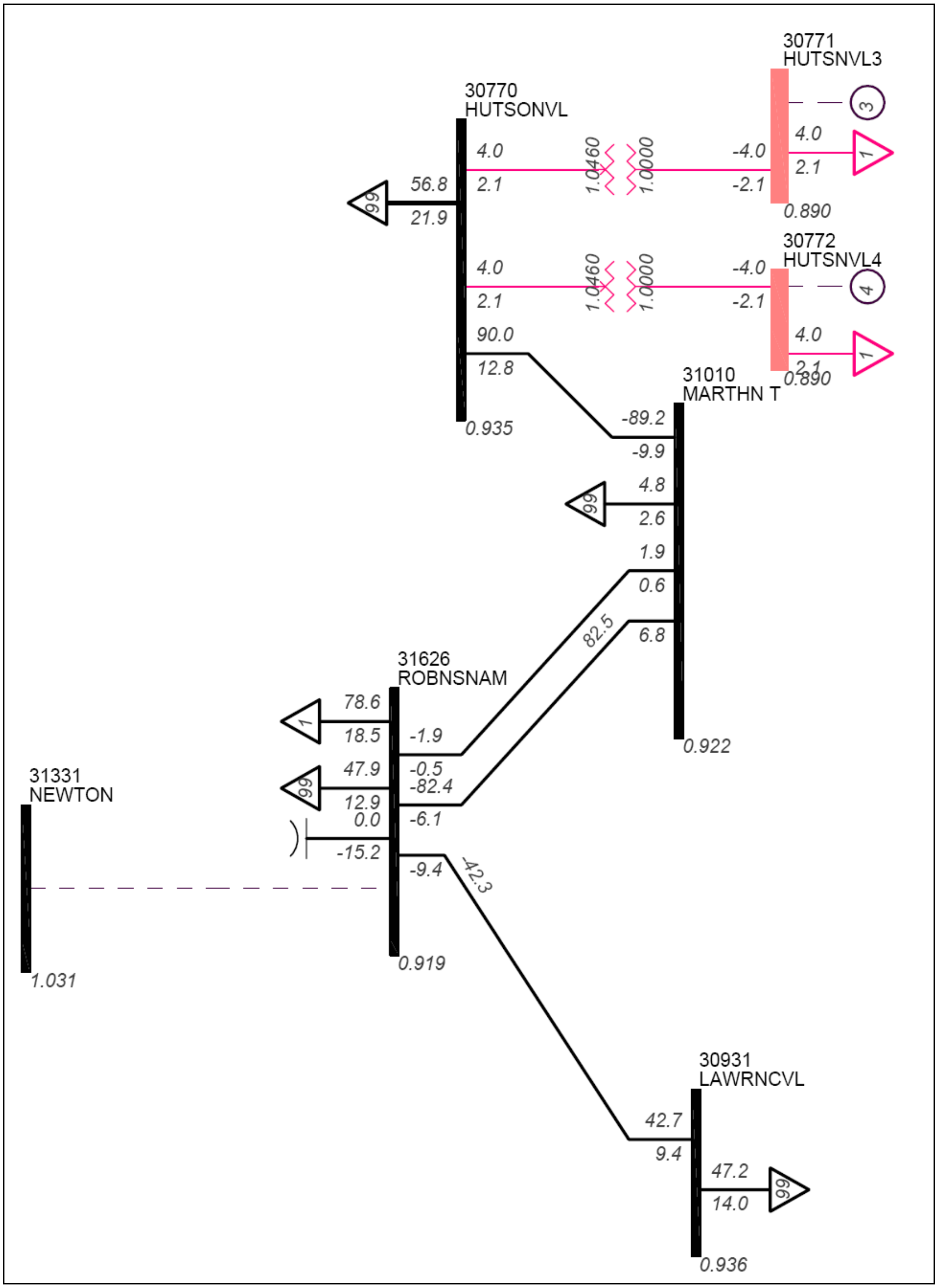

Figure 5.2-12: Project 783 study area in critical contingency 2013

Alternatives Considered:
None. This project is a cost effective solution

Cost Allocation:
This is a Baseline Reliability Project which is not eligible for regional cost sharing because it is less than $5 million.

5.2.2 New Generation Interconnection Projects

The following projects have Network Upgrades, therefore, they are all eligible for cost allocation per EMT. One of the projects has 100% allocation to the Pricing Zone where the generator is located--the local pricing zone. Needs for these projects are determined by EMT governed interconnection study process. Details of these studies are posted at http://www.midwestiso.org/publish/Folder/3e2d0_106c60936d4_-76840a48324a?rev=4. Projects which have regional cost sharing will be discussed briefly below Table 5.2-6.

Table 5.2-6 Generator Interconnection Projects

PrjID	TO	Project Name	Need Summary
1263	DEM	Network upgrades associated with 420 MW at Edwardsport	GI driven. G431: Edwardsport generator interconnection See below for cost sharing information.
1620	CWLP	Network upgrades associated with 200 MW unit 4 at Dallman	GI driven. G412: Dallman unit 4 generator interconnectoin

Project 1263: G431 Edwardsport

Transmission Owner: Duke Energy Midwest

Project Description:
This project installs a new 345 kV ring bus, an in-and-out tap of Wheatland-Amo 345 kV line and associated relaying upgrades at existing substations. The estimated cost of this project is $7.6 million. The expected in service date is May 2011.

Project Justification:
Required for interconnection of new generation facility per requisite studies.

Cost Allocation:
This is a Generator Interconnection Project which is eligible for regional cost sharing. The estimated cost of the project which is eligible for regional cost sharing is $3,793,500. There is postage stamp cost allocation for this 345 kV project. The top three pricing zone allocations are: Cinergy (Duke Energy Midwest) 82.31%, FirstEnergy 2.58%, and ATC LLC 2.42%. Appendix A1 contains cost allocation calculations including all postage allocations.

5.2.3 New Transmission Delivery Service Projects

None for Central Planning Region.

5.2.4 New Other Projects

None for Central Planning Region.

5.3 East Planning Region

5.3.1 New Baseline Reliability Projects

Project 612: Hiple 345/138 kV Transformer #2

Transmission Owner: NiSource.

Project Description:
Install a second 345/138 kV 560 MVA transformer at Forrest G. Hiple Substation: The total project cost is estimated at $5,799,600. Costs eligible for postage stamp allocation are 345 kV breakers, circuit switchers and substation work with an estimated cost of $1,454,915. Costs eligible for sub-regional allocation are 345/138 kV transformer and 138 kV breaker with an estimated cost of $4,344,699. The expected in service date is May 2008.

Project Justification:

Existing Hiple and Leesburg 345/138 kV transformers are the only 345 kV sources in the area with most of the underlying system connected via Hiple 138 kV substation. Loss of the 345 kV source at Hiple takes out a key 345 kV source into the area resulting in a number of thermal and voltage violations for various contingencies. Addition of a 2nd 345/138 kV transformer adds a new source in the area with the underlying system not completely dependent on one 345/138 kV transformer in the area.

Outage of existing 345/138 kV Hiple transformer (Category B) overloads the Northeast to Goshen 138 kV line to 100% of its emergency rating during 2013 summer peak condition. See Figure 5.3-2 and Figure 5.3-5 below for before and after power flow one-line diagrams.

Breaker failures at Hiple 345 kV ring bus (Category C2) involving outage of Hiple 345/138 kV transformer and Hiple-Leesburg 345 kV line or Hiple-Collingwood 345 kV line result in overloads on the Leesburg to Northeast to Goshen138 kV line.

Double contingencies involving loss of other 138 and 345 kV lines supplying power to Goshen load in addition to existing 345/138 kV Hiple transformer overload 138 kV lines in the area. The worst of these is the loss of Northeast to Goshen 138 kV line and Hiple 345/138 kV transformer which causes very low voltages in the area in addition to thermal overloads. See Figure 5.3-4 and Figure 5.3-7 below for before and after power flow one-line diagrams of this C3 event. Thermal overloads are seen on lines feeding power from the east after the above contingency essentially removes sources to the west of Goshen load including 345 kV source into the area. Mitigation would require dropping entire load at Goshen of 162 MW (~4.5% of NIPSCO load). An additional load of 90 MW would be lost following tripping of severely overloaded lines as a result of the same contingency. No reasonable redispatch was found that alleviated all overloads and voltage issues.

Table 5.3-1 below lists the contingencies which are addressed by the Hiple 345/138 kV second transformer project.

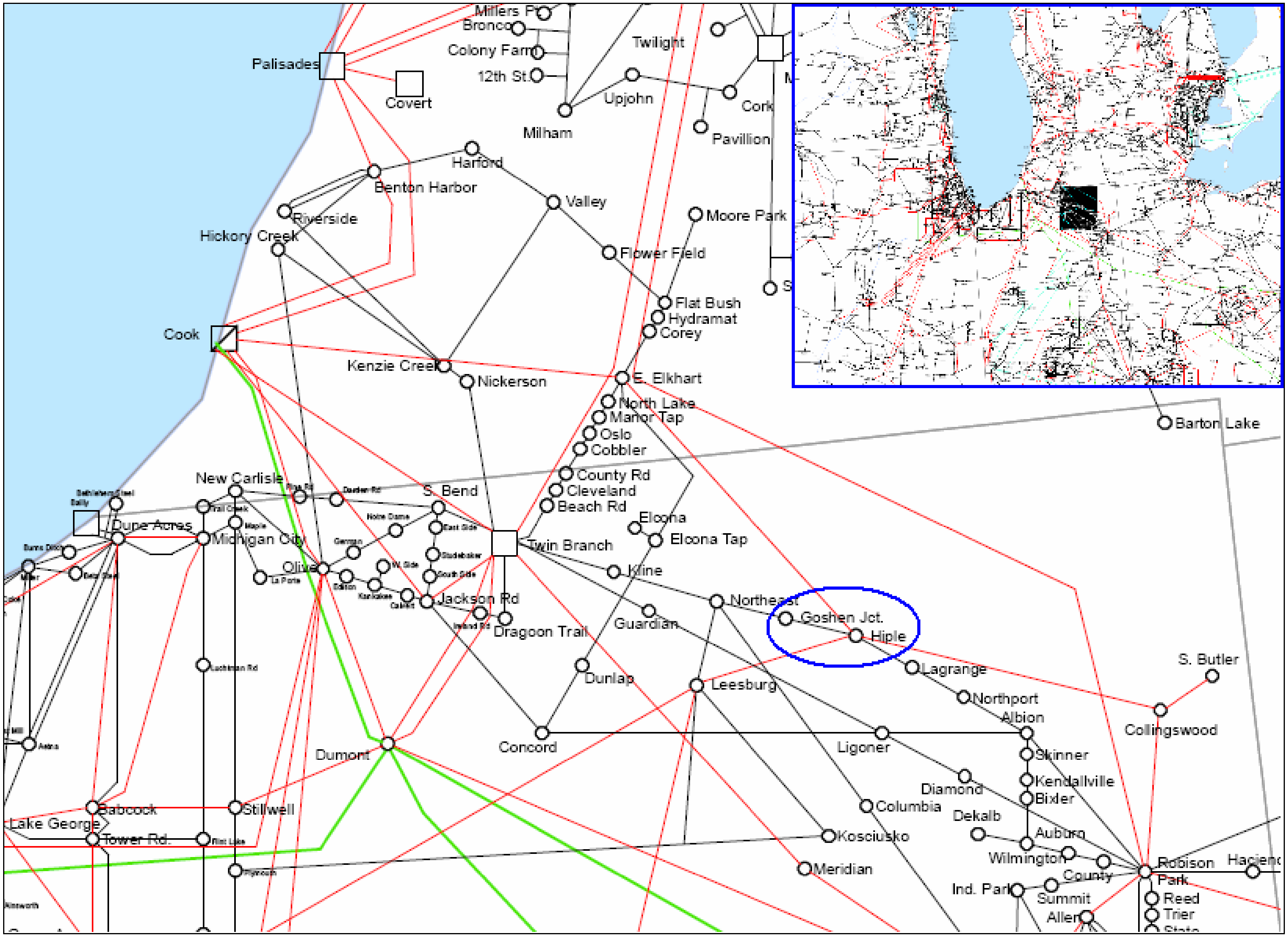

Figure 5.3-1: Geographic transmission map of Project 612 study area

Table 5.3-1 Project 612 Contingency Drivers

Need Driver	Contingency	Cont Type	Rating (MVA)	Year (Load Level)	Pre-project Loading	Post-project Loading
Goshen Junction to Northeast 138 kV	Hiple 345/138 kV Transformer	B	287	2013	100.1%	38.5%
Goshen Junction to Northeast 138 kV	Hiple to Collingwood 345 kV Hiple 345/138 kV Transformer	C2	287	2013	105.5%	31.9%
Leesburg to Northeast 138 kV	Hiple to Collingwood 345 kV Hiple 345/138 kV Transformer	C2	222	2013	102.5%	50.1%
Goshen Junction to Northeast 138 kV	Hiple to Leesburg 345 kV Hiple 345/138 kV Transformer	C2	287	2013	104.4%	56.4%
Leesburg to Northeast 138 kV	Hiple to Leesburg 345 kV Hiple 345/138 kV Transformer	C2	222	2013	103.9%	78.2%
Leesburg to Northeast 138 kV	Kline to Northeast 138 kV Hiple 345/138 kV Transformer	C3	222	2013	123.9%	62.6%
Leesburg 345/138 kV Transformer	Kline to Northeast 138 kV Hiple 345/138 kV Transformer	C3	222	2013	104.1%	71.6%
Albion to Northport 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3	184	2013	185.6%	10.7%
Auburn to Dekalb 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3	45	2013	121.3%	45.2%
Hiple to Lagrange 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3	287	2013	111.7%	49.5%
Lagrange to Northport 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3	143 *	2013	188.3%	19.1%
Burnt Lake 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3		2013	0.79	0.99
Goshen Junction 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3		2013	0.44	0.98
Lagrange 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3		2013	0.59	0.99
Dekalb 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3		2013	0.85	0.99
Hiple 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3		2013	0.49	1.00
Northport 138 kV	Goshen Junction to Northeast 138 kV Hiple 345/138 kV Transformer	C3		2013	0.66	0.99

* 17LAGRNG to 17NRTHPT 138 was recently re-rated at SN=SE=156 MVA

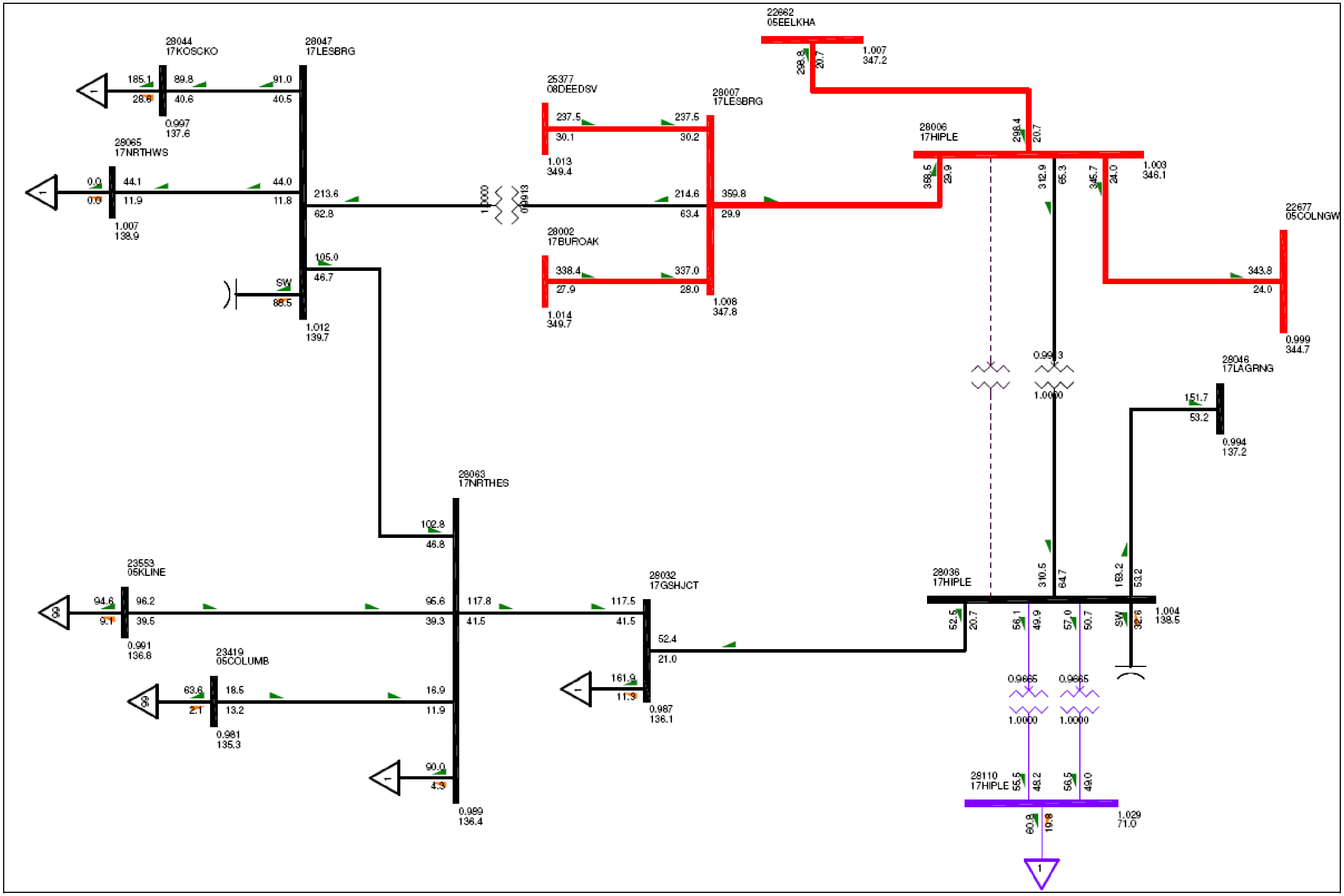

Figure 5.3.2: Pre-Project System Intact 2013

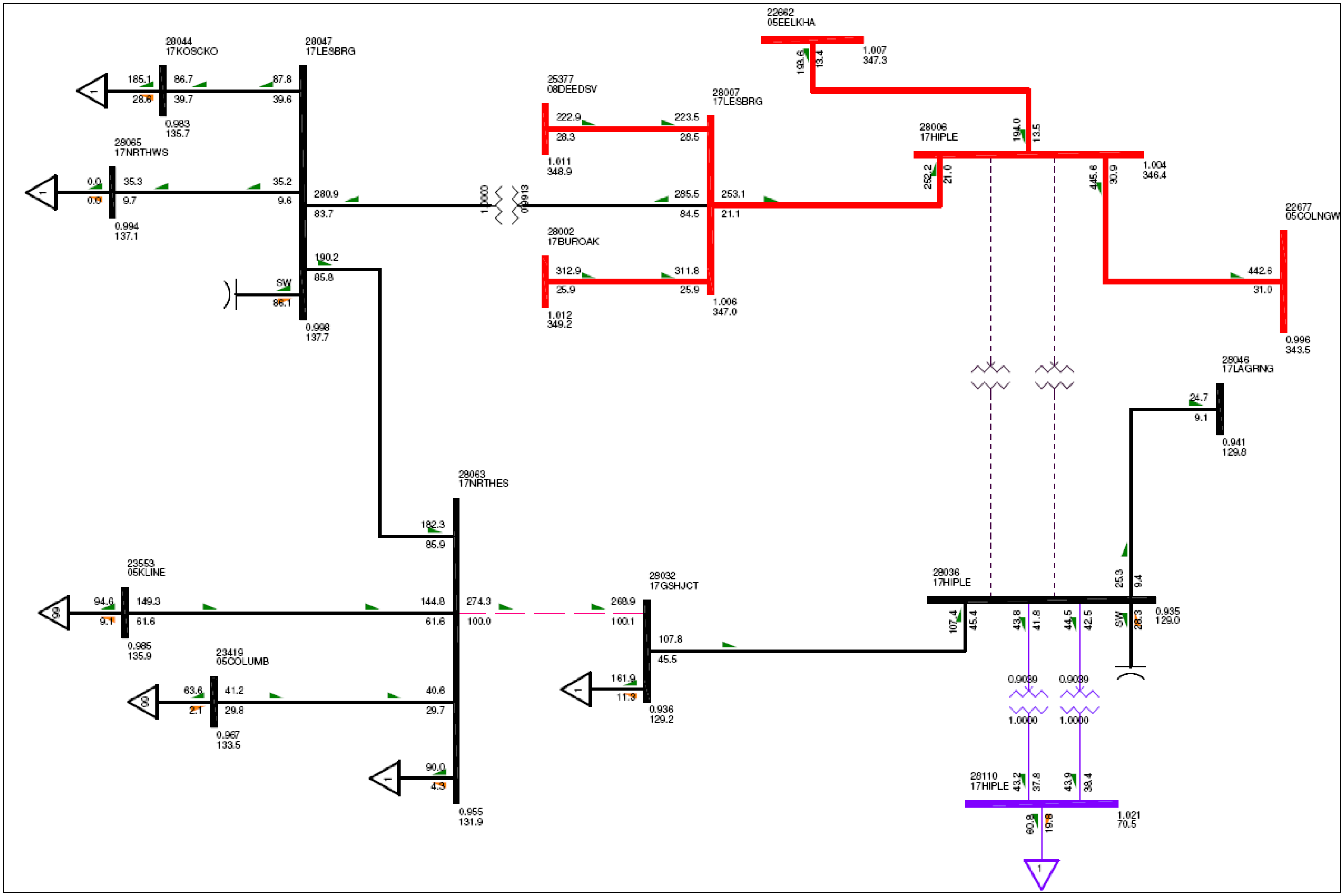

Figure 5.3.3: Pre-Project Hiple 345/138 kV transformer outage 2013

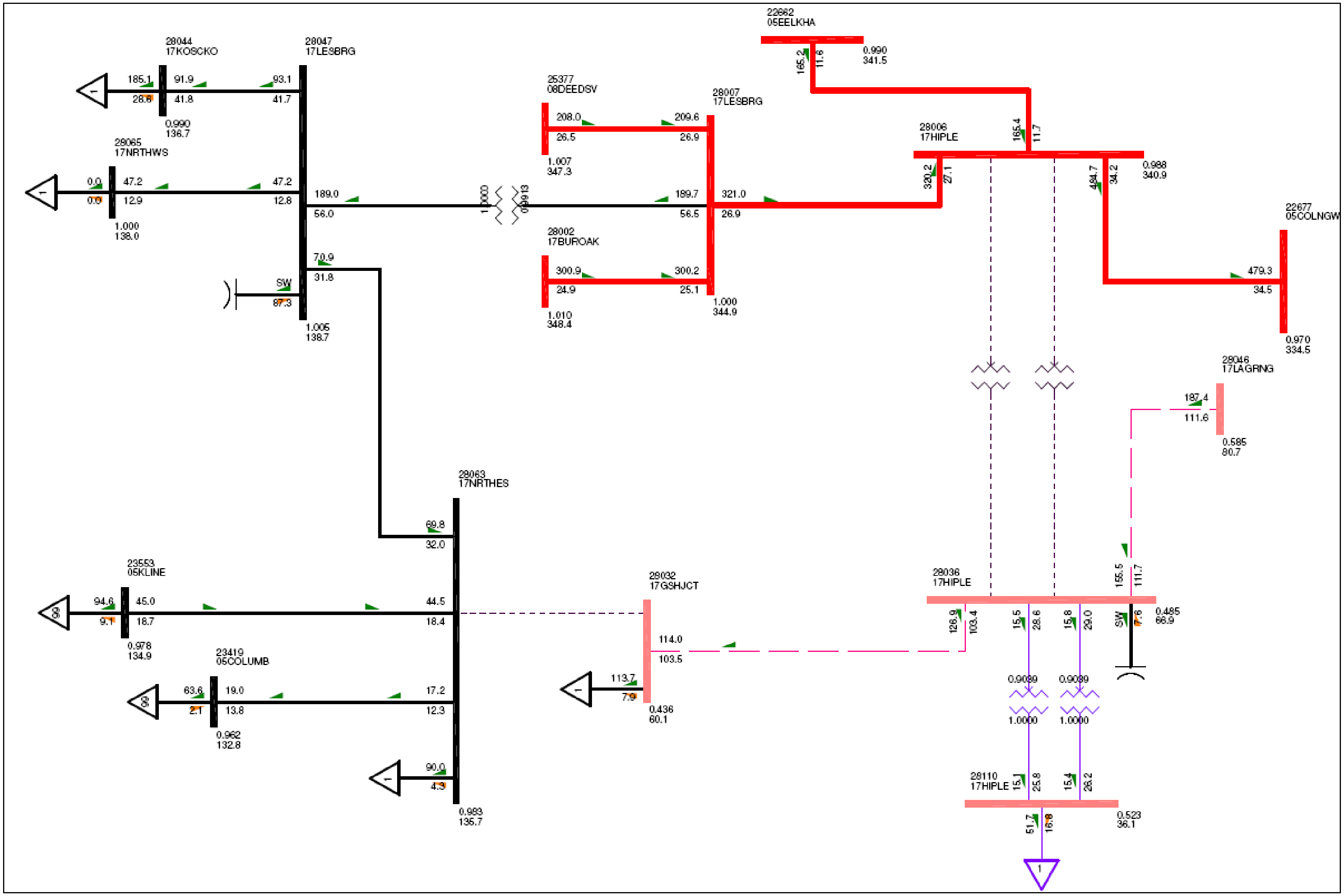

Figure 5.3.4: Pre-Project Hiple 345/138 transformer & Northeast-Goshen 138 kV line outages 2013

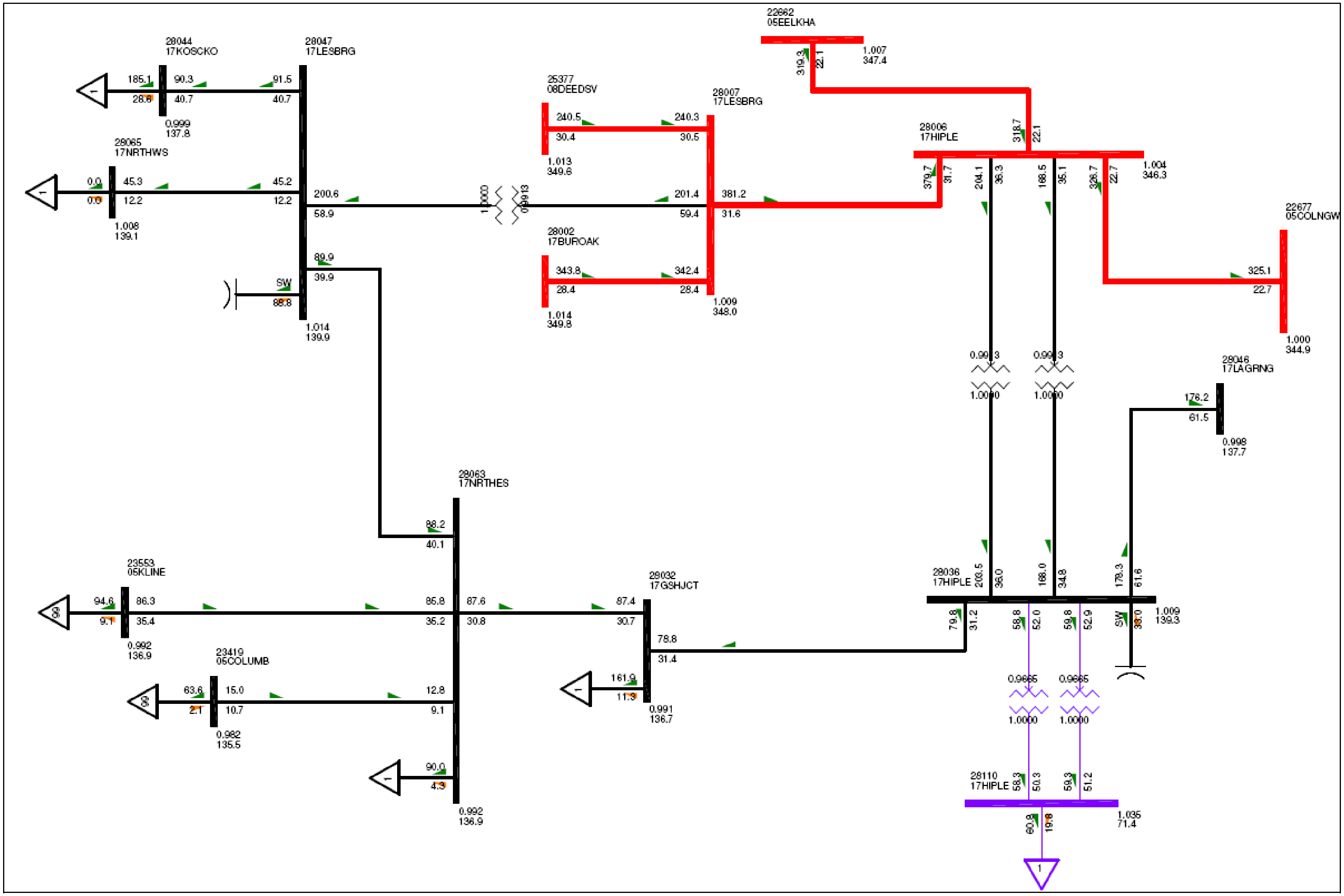

Figure 5.3.5: With Project 612 System Intact 2013

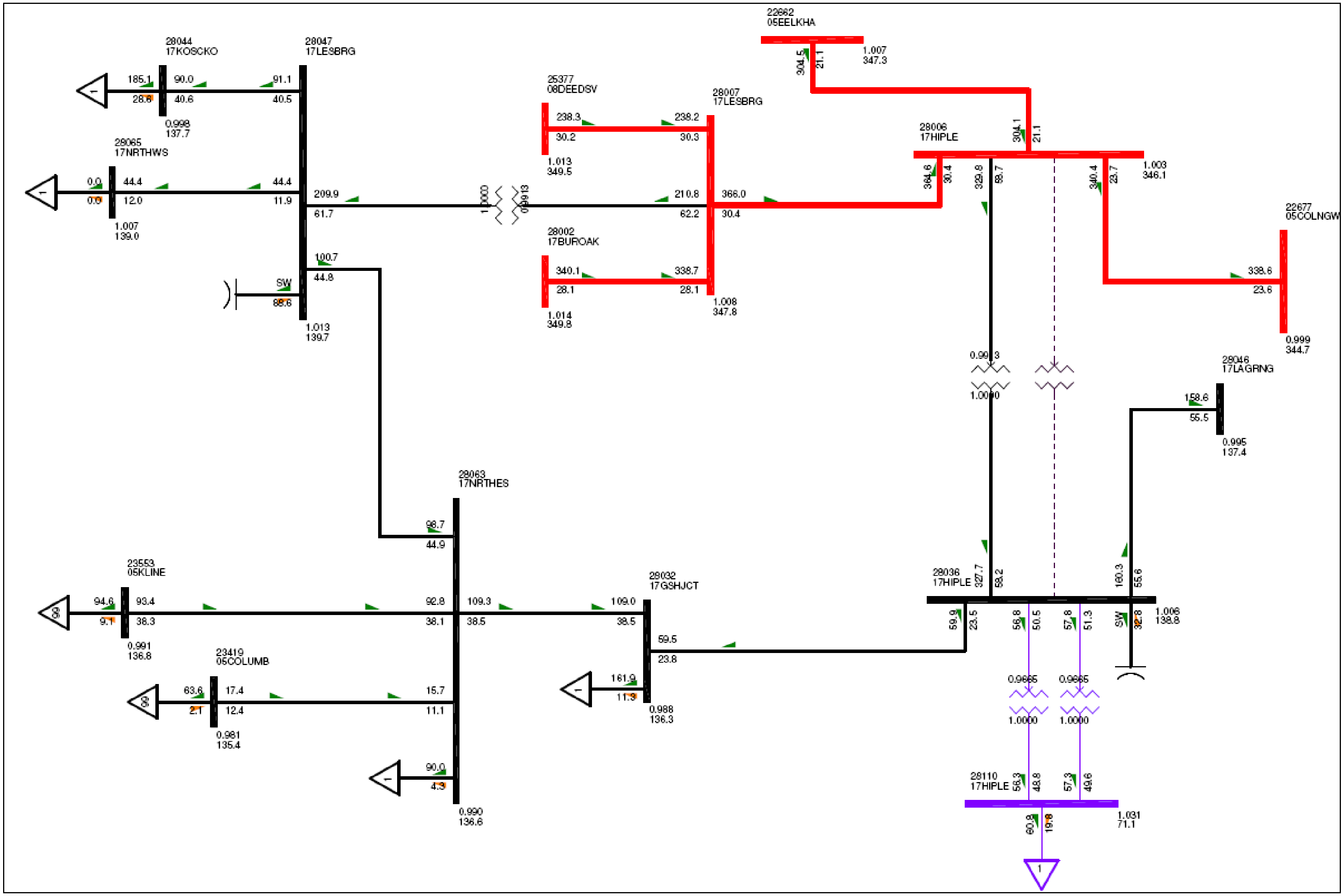

Figure 5.3.6: With Project 612 Hiple 345/138 kV transformer outage 2013

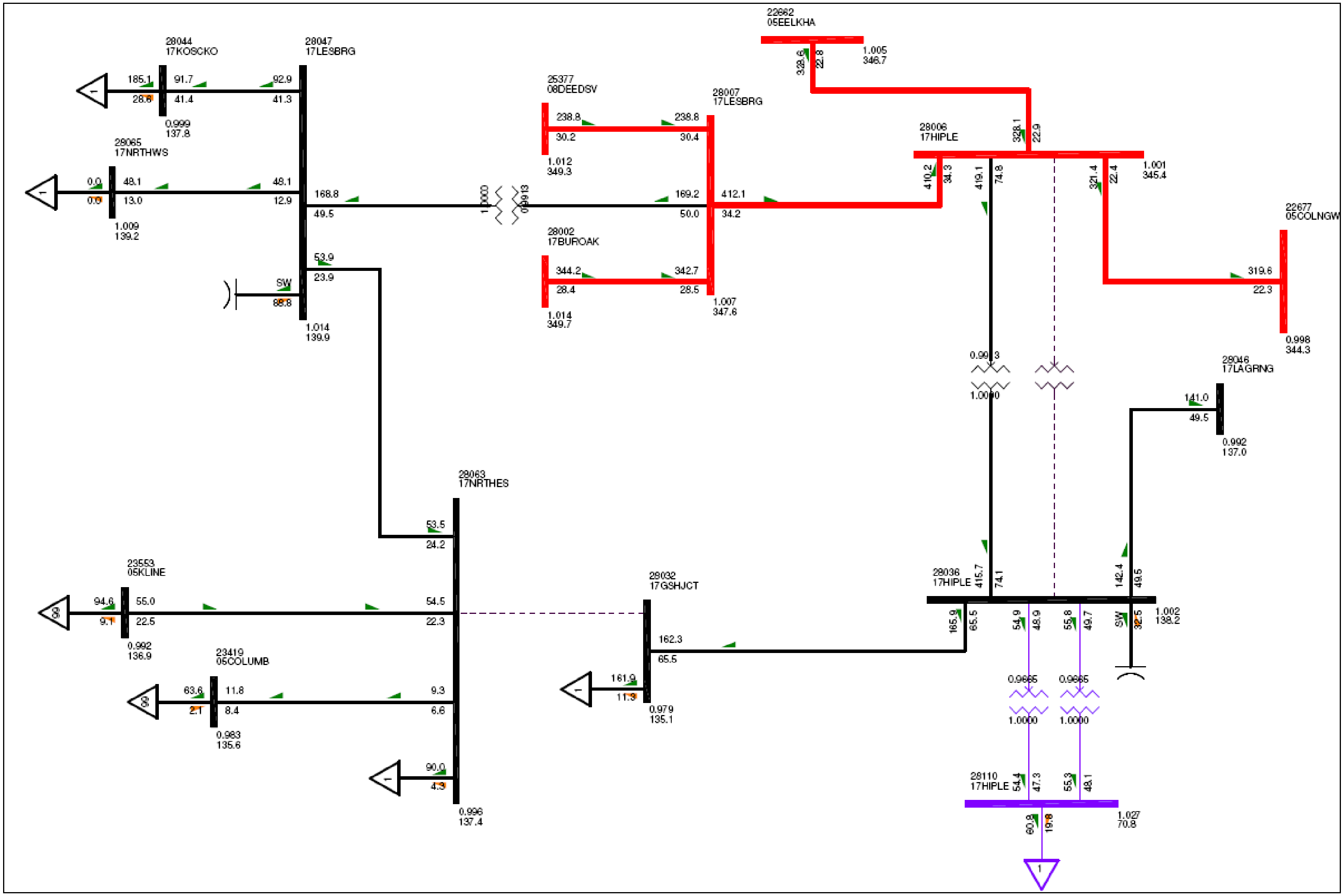

Figure 5.3.7: With Project 612 Hiple 345/138 transformer & Northeast-Goshen 138 kV line outages 2013

Alternatives Considered:
For Category B and Category C2 events:
Reconductor 20 mile line from Leesburg to Northeast to Goshen 138 kV line: Estimated Cost: $4,563,400. This was rejected because it's close to Project cost but does not reduce exposure to C3 events. The addition of the second Hiple 345/138 kV transformer eliminates the category C3 contingency violations in the area by bringing an additional source.

Reconductor only Northeast to Goshen 138 kV line section and upgrade the bus design at Hiple 345 kV sub to breaker and a half scheme. This would cost more than the current project.

For Category C3 events:
Shed 162 MW load at Goshen 138 kV substation for Category C3 events (~4.5% of NiSource Load) and lose an additional 90 MW due to tripping of severely overloaded lines for the same contingency.

Cost Allocation:
This is a Baseline Reliability Project which is eligible for regional cost sharing. The estimated cost of project is $5,799,600. The project has 345 kV components which are eligible for postage stamp allocation. The top three Pricing Zones are NIPS with 88.7%, METC with 4.5%, and Cinergy (Duke Energy Midwest) with 3.0%. See Appendix A1 for complete details of cost allocation for this project.

5.3.2 New Generation Interconnection Projects

The following Generation Interconnection projects have Network Upgrades which are eligible for regional cost sharing. Note that Generation Interconnection Projects have 50/50% cost allocation with 50% of cost shared using Baseline Reliability Project allocation method and the other 50% paid for by interconnecting party. The following project did not have any cost allocated outside of the local Pricing Zone.

PrjID	TO	Project Name	Need Summary
1615	NIPSCO	G439 - Benton County Wind	Network Upgrades associated with 100 MW wind farm in Benton County IN

5.3.3 New Transmission Delivery Service Projects

None in East Planning Region.

5.3.4 New Other Projects

None in East Planning Region.

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Section 6.0 MTEP Reliability Analysis

In MTEP07, the following reliability analyses were performed: steady-state contingency analysis, dynamic stability analysis, voltage stability analysis, and generation deliverability analysis. The analysis performed and summary of results is described in Section 6. This analysis is one of the studies that the Midwest ISO performs to assess the system performance for events described in Table 1 of the NERC TPL Standards. The NERC TPL Standards can be found on the NERC website at: http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html

6.1 Steady-State Contingency Analysis

6.1.1 Description of Analysis Performed

The MTEP07 study evaluated the thermal loadings of lines and transformers and bus voltages for the Midwest ISO members' system including tie lines above the 100 kV voltage level under both pre-contingency and post-contingency system conditions for NERC Category A, B, C and D events. Neighboring systems were monitored and contingencies analyzed to identify any seams related issues, specifically, do any neighboring contingencies impact Midwest ISO members or do our contingencies impact our neighbors' systems. The Study was conducted primarily on 2013 summer peak system condition and with select analysis on 2018 summer peak condition using ShawPTI's PSS/E and MUST digital simulation programs.

Overview

The following methodology was used in performing the reliability studies. Contingency analysis was performed on MTEP 2013 summer peak blended contractual dispatch model. Results were then transferred to a results database to enable linkage of system needs to projects which address those needs. The preliminary results of initial analysis were posted for review by Expansion Planning Group and interested stakeholders. If there were any concerns with the results, the stakeholders would communicate those to Midwest ISO staff for consideration. Comments on results were documented in results database for reference. Confirmed system issues identified in initial analysis were then mapped to projects in the Midwest ISO Project Database. If a project did not exist, Midwest ISO staff would work with Transmission Owners to develop system upgrades proposals and test the proposed upgrades for effectiveness. This method was used primarily for Category A, B, and some C violations. If an identified system need (overload or low/high voltage) had an existing operating procedure, that was documented. Non-converged results were also reviewed to determine if non-convergence was a solution abnormality or if it was a system issue which needed to be addressed.

Category C Results Review

NERC Planning Standards allow for planned and controlled load shedding if necessary for Category C events. Category C3 events also have a period for manual system adjustment. Because the contingency files typically contain the two Category B events which comprise the Category C3 forced outage event only, and not the allowable associated manual adjustments and/or load shedding, it may not be appropriate to say the Category C3 event is a criteria violation when flagged in this analysis. For example, a NERC Category C3 event is a single contingency, followed by operator adjustments, followed by another single contingency. The event is typically not modeled with operator actions in the contingency files and an overload is flagged in the analysis. However, with appropriate operator action after the first event, the overload would not occur after the second contingency occurs. That is why initial Category C event results should be considered exceptions until review determines if an actual violation may exist in the 2013 plan year.

NERC Planning Standards require that Category C events do not exceed applicable ratings or result in uncontrolled cascading outages. The standards state "Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems." Therefore, this study screened the Category C events which resulted in criteria exceptions to determine if the event may be a criteria violation and warrant additional analysis. NERC Planning Standards do not provide an objective definition for cascading. Therefore, the desired outcome of the screening was identifying the approximate amount of MW load which would be shed and/or the number of additional lines which would trip because of the event, to indicate cascading potential. The following screening procedure / guidelines were used:

> Cascade Screening Methodology
> Events which result in overloads greater than 125% of emergency rating were reviewed for cascading potential. A tripping proxy of 125% of emergency rating was assumed. The overloaded branch was taken out of service plus all others branches over 100% of emergency rating. The case powerflow case was solved and checked for additional overloads. Any new overload branches were taken out of service and the powerflow case was resolved. The process repeated until case had all overloads less than 100% or solution diverged. If case solved, the amount of load shed was estimated. If case diverged, the event has potential for uncontrolled cascading.

If an event has cascading potential or exceeds applicable ratings, then a special protection scheme (SPS) may need to be implemented or a system upgrade proposed. Because this is a fast screen of cascading potential, any event which appears to be cascading should be reviewed using line specific tripping values which require a thorough review of design parameters.

Validation of Baseline Reliability Plan

After all required proposals are developed, the Project Database will contain the projects which comprise the 2013 Baseline Reliability Plan. To confirm that the plan works well together, the Final 2013 powerflow base case with Appendix A and Appendix B projects was developed and AC contingency analysis was performed to confirm that the integrated plan satisfies planning criteria. The end result of Final Plan analysis should have little or no planning criteria violations. If issues persist or Baseline Reliability Plan results in new issues, then Midwest ISO will work with our members to develop additional proposed upgrades or operating procedures as necessary.

The following sections summarize the results of this contingency analysis. The details of the analysis are located in Appendix D1 for each of the three MTEP Planning Regions. The appendices contain the results of the contingency analysis and the plan to address the issues identified. Depending on the type of contingency the plan may be a transmission system upgrade project or an operating guide or operator action or load shedding.

6.1.2 West Steady-State Contingency Results

West Planning Region Overview

The Midwest ISO West Planning Region is comprised of the following transmission owning/operating members: American Transmission Company (ATC LLC) comprised of ALTE, WEC, WPS, MGE, UPPCO systems; Alliant Energy West (ALTW), Xcel Energy North (XEL), Minnesota Power (MP), Great River Energy (GRE), Southern Minnesota Municipal Power Association (SMMPA), and Otter Tail Power Company (OTP). The following transmission owners are contained with other members control areas in the models: Montana-Dakota Utilities (MDU) and Northwestern Wisconsin Electric Company (NWEC).

The West Planning Region also contains the following transmission owners who are in Midwest ISO Reliability Coordination footprint, but are not Midwest ISO transmission owning members: MidAmerican Energy Company (MEC), Muscatine Power and Water (MPW), Dairyland Power Cooperative (DPC), Western Area Power Administration (WAPA), Basin Electric Power Cooperative (BEPC), Missouri River Energy Services (MRES), and Omaha Public Power District (OPPD), and Lincoln Electric System (LES).

The West Planning Region is contained within the following states: Wisconsin and Upper Michigan, Iowa, Minnesota, North Dakota, South Dakota, Nebraska. The Balancing Authority (BA) load, generation dispatched, and interchange in the 2013 Summer Peak, 2018 Summer Peak models are shown in the tables below.

Table 6.1-1
West Balancing Area Summary for 2013/2018 Summer Peak Models

BA #	BA Name	2013 Summer Peak				2018 Summer Peak			
		Gener-ation	Load	Loss	Inter-change	Gener-ation	Load	Loss	Inter-change
331	ALTW	4,306	4,769	83	-546	4,884	4,792	107	-15
364	ALTE	4,554	3,648	129	776	3,976	4,165	178	-368
365	WEC	7,484	7,831	172	-521	9,151	8,356	178	616
366	WPS	2,612	3,116	79	-584	2,785	3,445	81	-742
367	MGE	265	849	15	-600	84	922	28	-870
368	UPPC	26	170	6	-150	108	200	6	-98
600	XEL	10,372	11,842	301	-1,772	11,274	12,964	380	-2,072
608	MP	2,020	1,859	89	72	2,079	2,044	78	-43
613	SMMPA	237	600	4	-367	242	600	2	-360
618	GRE	2,582	1,743	92	745	2,629	1,971	100	555
626	OTP	2,118	2,041	103	-26	1,631	2,129	78	-577
652	MDU (in WAPA)	292	500	194 (WAPA)	1246 (WAPA)	273	500	183 (WAPA)	1368 (WAPA)

West Region Summary of Results

In West region, there were 3 thermal issues and 37 voltage issues under system intact (Category A), 238 thermal issues and 156 voltage issues under Category B contingencies, 72 thermal issues and 497 voltage issues under Category C1/C2/C5 contingencies, and 561 thermal issues and 330 voltage issues under Category C3 contingencies.

148 thermal issues have overloads above 125% of their corresponding ratings. They were reviewed for Interconnection Reliability Operating Limit (IROL). No cascading issues were found. If the proposed projects to mitigate these thermal issues would not be in service by 2013, appropriate mitigation plans such as load shedding, generation redispatch, system reconfiguration are needed to bring the overloaded facilities within their System Operating Limits (SOL). See Appendix D1 West for the detailed steady-state contingency results with the associated plans to address the identified issues.

West Region Plans to Address Identified Issues

In West region, 449 thermal issues and 670 voltage issues will be mitigated by the previously identified projects, 193 thermal issues and 291 voltage issues will be mitigated by the new proposed projects, and 232 thermal issues and 59 voltage issues will be mitigated by the pre-existing Special Protection Systems (SPS), pre-existing operating guides, and other methods such as generation redispatch, system reconfiguration, load shedding. See Appendix D1 for the detailed plans to address the identified issues.

West Region Open Issues

In West Region, there are no remaining thermal/voltage issues under system intact (Category A) and Category B contingencies. For Category C, there are 98 remaining thermal issues and 44 remaining voltage issues which can all be mitigated by some operating steps, such as generation redispatch, system reconfiguration, or load shedding. See Appendix D1 for the open issues for which appropriate operating guides or actions will be developed.

6.1.3 Central Steady-State Contingency Results

Central Planning Region Overview

The Midwest ISO Central Planning Region is comprised of the following transmission owning members: Hoosier Energy (HE), Duke Energy Midwest (DEM), Indianapolis Power & Light Company (IP&L), Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana (Vectren), Ameren MO, Ameren IL, City of Columbia, MO (CWLD), City Water, Light and Power (CWLP, Springfield, Illinois), and Southern Illinois Power Cooperative (SIPC). The following transmission owners do not have control areas in the model but are contained with member control areas: Indiana Municipla Power Agency (IMPA) and Wabash Valley Power Association (WVPA). The Central Planning Region includes portions of the states of Indiana, Illinois, and Missouri. The control area load, generation, and interchange in the MTEP07 2013 summer peak and 2018 summer peak cases are shown in the table below.

Table 6.1-2
Central Balancing Area Summary for 2013/2018 Summer Peak Models

BA #	BA Name	2013 Summer Peak				2018 Summer Peak			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
207	HE	1,859	855	45	960	1,685	855	42	788
208	DEM	15,071	14,645	566	-151	13,958	15,745	557	-2,354
210	Vectren	1,844	2,081	31	-269	1,601	2,197	37	-633
216	IP&L	3,205	3,359	84	-241	3,241	3,593	81	-437
355	CWLD	146	315	2	-171	76	315	2	-241
356	AmerenMO	9,790	9,398	190	227	8,211	9,879	181	-1,824
357	AmerenIL	12,059	10,593	245	1,189	13,521	11,127	268	2,095
360	CWLP	492	489	3	0	572	513	4	55
361	SIPC	390	279	10	101	226	279	5	-58

Central Region Summary of Results

Steady-state AC contingency analysis of the MTEP 2013 and 2018 Summer Peak models was performed. NERC Category A, B, C and D events were analyzed with initial 2013 summer peak case.

The AC analysis of the preliminary 2013 summer peak model resulted in several thermal and voltage issues identified in the Central Region. There were no Category A contingency issues identified. There were 11 thermal issues and 4 voltage issues caused by 16 Category B contingencies. There were 60 thermal issues and 70 voltage issues caused by 52 Category C1, C2 & C5 contingencies. There were 95 thermal issues and 120 voltage issues caused by 81 Category C3 contingencies. Please note, a single contingency may result in multiple thermal or voltage issues and multiple contingencies may result in the same thermal or voltage issues.

There were 26 thermal overloads > 125% of emergency rating caused by 13 category C3 contingencies and 19 >125% overloads were caused by 11 category C1, C2 & C5 contingencies. They were reviewed to determine if they may be Interconnection Reliability Operating Limit (IROL). No potentially cascading issues were found. If the proposed projects to mitigate these thermal issues would not be in service by 2013, appropriate mitigation plans such as load shedding, generation redispatch, system reconfiguration are needed to bring the overloaded facilities within their System Operating Limits (SOL). See Appendix D1 Central for the detailed steady-state contingency results with the associated plans to address the identified issues.

Central Region Plans to Address Identified Issues

Plans to address identified issues include transmission system upgrades, operation guides, operator actions and load shedding. These plans were developed to address the identified issues in 2013 summer peak model. Six new Appendix A/B/C projects (plus 2 in process) were developed to address 9 thermal issues and 4 voltage issues resulting from Category B contingencies. One operating procedure was developed to address 2 thermal issues.

Twelve thermal issues and 34 voltage issues resulting fromCategory C125 contingencies were addressed with 3 new Appendix B/C projects. Operating procedures were developed to address 15 thermal issues and 5 voltage issues. The plan for each identified issues is listed in Appendix D1 Central.

Central Region Open Issues

There are no open Category A or B issues in Central region. There are 32 thermal and 32 voltage issues remaining for Category C1/C2/C5 events. These will require short-term ratings, load shedding or development of system upgrades. Central Region has 45 thermal and 80 voltage issues still under review for Category C3 events. Load shed values will be determined and upgrades may be identified. See Appendix D1 Central for details.

6.1.4 East Steady-State Contingency Results

East Planning Region Overview

The Midwest ISO East Planning Region is comprised of the following transmission owning/operating members with controls areas modeled: FirstEnergy (FE d/b/a ATSI), ITC*Transmission* (ITC), Michigan Electric Transmission Company (METC), Wolverine Power Cooperative within METC zone (WPSC), and Northern Indiana Public Service Company (NIPSCO). The following transmission owners are contained in ITC/METC Michigan control areas: Michigan South Central Power Agency (MSCPA) and Michigan Public Power Agency (MPPA).

The East Planning Region is contained within the following states: Michigan and Indiana and Ohio. The Balancing Authority (BA) load, generation dispatched, and interchange in the 2013 Summer Peak, 2018 Summer Peak models are shown in the tables below.

Table 6.1-3
East Control Area Summary for 2013/2018 Summer Peak Models

BA #	BA Name	2013 Summer Peak				2018 Summer Peak			
		Generation	Load	Loss	Interchange	Generation	Load	Loss	Interchange
202	First Energy	13,650	15,314	405	-2,066	15,170	16,203	434	-1,464
217	NIPSCO	3,170	3,717	61	-609	3,705	3,935	66	-296
218	METC	11,976	11,091	434	452	13,514	11,522	466	1,528
219	ITC	12,056	12,520	288	-752	12,585	12,737	295	-448

East Region Summary of Results

In East region, there were 2 thermal issues and 9 voltage issues under system intact (Category A), 57 thermal issues and 121 voltage issues under category B contingencies, 204 thermal issues and 438 voltage issues under category C1/C2/C5 contingencies, and 144 thermal issues and 358 voltage issues under category C3 contingencies. See Appendix D1 for the detailed steady-state contingency results with their mitigation plans associated.

The East Planning region contained several MTEP08 Reference Future portfolio generators which are not associated with generation interconnection process. A sensitivity analysis was performed on the MTEP07 2013 thermal constraints resulting from all Category B and most Category C125 contingencies to determine effects of these proxy generators. Among 7 Reference Future units, three were in the East region. Two units were in ITC footprint (Greenwood 90 MW, Bell River 320 MW) and one was in FirstEnergy (Lemoyne 375 MW). Based on the analysis, it was concluded that the Reference Future units do not have significant impact on constraints seen in the 2013 analysis. See Appendix D1 for Reference unit sensitivities on constraints.

23 thermal issues at 100 kV and above transmission level, had overloads greater than 125% of their corresponding emergency ratings. Of these, 17 thermal issues were category C3 contingent overloads for which redispatch and or load shed schemes may be applied. Six other thermal issues greater than 125% for category C1/C2/C5 contingencies were reviewed for Interconnection Reliability Operating Limit (IROL). No cascading issues were found. If the

proposed projects to mitigate these thermal issues would not be in service by 2013, appropriate mitigation plans such as load shedding, generation redispatch, system reconfiguration are needed to bring the overloaded facilities within their System Operating Limits (SOL).

East Region Plan to Address Identified Issues

In East region, 21 thermal issues and 7 voltage issues will be mitigated by the previously identified projects, 46 thermal issues and 114 voltage issues will be mitigated by the new proposed projects, and 171 thermal issues and 322 voltage issues will be mitigated by the pre-existing Special Protection Systems (SPS), pre-existing operating guides, and other methods such as generation redispatch, system reconfiguration, load shedding. See Appendix D1 for the detailed plans to address the identified issues.

East Region Open Issues

In East Region, there are no remaining thermal/voltage issues under system intact (Category A). There are 14 remaining thermal and 42 voltage issues for category B. All thermal violations are in the Wolverine 69 kV system. There are 29 remaining thermal and 102 voltage issues for category C1/C2/C5 contingencies of which 11 thermal and 42 voltage issues are at 100 kV level and above. There are 121 remaining thermal and 310 remaining voltage issues of which 80 thermal and 215 voltage issues are at 100 kV level and above for category C3 contingencies which may all be mitigated by some operating steps, such as generation redispatch, system reconfiguration, or load shedding. There is one Category B and 2 Category C5 contingencies in East which do not converge in Powerflow. See Appendix D1 for the open issues for which appropriate operating guides will be developed.

6.2 Dynamic Stability Analysis

6.2.1 Analysis Performed

MTEP07 study performed a dynamic stability analysis on the MTEP 2013 Summer Off-Peak (70% load) with high West Region wind model. MTEP dynamic studied is to evaluate the dynamic stability of MISO system in 2013 summer under various disturbances. Critical disturbance events were selected based on TO's inputs, previous Midwest ISO and regional studies, non-converged contingencies of MTEP07 ACCC and voltage studies, and etc. The generator rotor angles and voltages of critical buses were used to determine the system stable or not. The stability criteria are listed below. There several types of unstable: generator unit out-of-step, low damping oscillation, long time transient voltage sage, etc.

Generally, large power transfers along long distance transmission lines can significantly reduce the power system stability. This situation normally occurs during the off-peak load condition, when more power is transferred from remote low price energy resource area to metro area. The off-peak 2013 case is selected as a severe condition for MTEP07 stability study. The topology of the off-peak case is same as the MTEP07 2013 summer peak model. The units in Midwest ISO footprint were dispatched by Security Constrained Economic Dispatch (SCED). The dynamic model building process is described in detail in this section.

Dynamic Simulation Settings

- Simulation time: 20 seconds
- Flat simulation prior to the disturbance: 2 seconds
- All controls (DC taps, PAR's, switched shunts) will be operational during 20 second run
- No manual adjustments will be allowed in 20 second run
- Existing operation guide and Special Protection Systems (SPS) are written in disturbance files.
- The convergence monitor is turned ON.
- The interval to tabulate the output channels in progress device (monitor or report): "Print every" =120
- The interval to write the channel to output file: "Write every" = 1

Stability Study Criteria

Disturbance performance is determined by are monitoring bus voltages and rotor angle oscillation. The damping ratio criteria are:

- Transient voltage deviation limits (up to 20 seconds): 0.7 p.u. $\leq V_{bus} \leq 1.2$ p.u.
- Transient voltage sags monitoring criteria after clearing the fault are summarized in table below. These criteria were manually checked only the transient voltage deviation exceeds the limits 0.7 p.u. $\leq V_{bus} \leq 1.2$ p.u.

Time after fault clearing	Allowable Maximum Transient Voltage Sag
First voltage sag	70% of nominal
Less than 15 cycles	80% of nominal
Less than 45 cycles	90% of nominal
Greater than 45 cycles	Steady State

Table 6.2-1: Transient Voltage Sag Monitoring Criteria

- Rotor Angle Oscillation Damping Ratio Limits (up to 20 seconds):
  - Midwest ISO proxy: $\zeta_i \geq 0.03$
  - MAPP: with fault: $\zeta_i \geq 0.0081633$, no fault line trip $\zeta_i \geq 0.0167660$

Description of Models Used
The 2013 summer off-peak (70% load) case was prepared for MTEP07 dynamic simulation based on MTEP07 2013 summer peak case. Midwest ISO members' control area load was scaled down to 70% of summer peak. After the demand adjustment, the generators in Midwest ISO footprint were dispatched as:

1) All exiting wind generators in Western region were dispatched at 90% of their rated capacities;
2) All strategy wind generators were dispatched at 15% of their rated capacities
3) All MUST run units were not changed
4) All other units in Midwest ISO footprint were dispatched by Security Constrained Economic Dispatch (SCED).
5) For dynamic simulations, the loads in Midwest ISO footprint were converted as: real power 100% constant current, reactive power 100% constant reactive power

The dynamic models were developed based on MTEP06 2011 summer peak models. The dynamic data of the new generator units were provided by Midwest ISO members or Midwest ISO Generator Interconnection group. The load flows on the three MAPP export flowgates are: MHEX = 1761 MW, NDEX = 1184 MW, MWSI = 408 MW. The 2013 off-peak model generation, load, and interchange for Midwest ISO member control areas is summarized in table below.

BA Number	BA Name	2013 Summer Off-Peak Case			
		Generation	Load	Losses	Net Scheduled Interchange
202	FIRSTENE	9706	10962	238	-1491
207	HE	1086	598	21	467
208	DEM	9447	10896	346	-1805
210	SIGE	1245	1711	22	-487
216	IPL	2431	2492	60	-124
217	NIPS	2497	2564	44	-110
218	METC	7533	7910	240	-622
219	ITC	8764	8822	190	-248
331	ALTW	3171	3340	60	-228
355	CWLD	17	315	3	-301
356	AMMO	7065	6549	128	384
357	AMIL	9267	7445	142	1678
360	CWLP	408	343	2	64
361	SIPC	99	195	5	-102
364	ALTE	2642	2684	89	-132
365	WE	6386	5655	124	605
366	WPS	2204	2380	59	-235
367	MGE	12	597	10	-596

BA Number	BA Name	2013 Summer Off-Peak Case			
		Generation	Load	Losses	Net Scheduled Interchange
368	UPPC	24	122	4	-102
600	XEL	7481	8538	252	-1310
608	MP	1754	1593	71	90
613	SMMPA	229	552	2	-326
618	GRE	1513	1217	77	217
626	OTP	1832	1496	79	257

Table 6.2-2 Summary of 2013 Summer Off-Peak Models

Description of system monitored
A common channel file was setup to monitor the system critical facilities including: large generation units, stability interfaces, all 230kV and above bus voltages in Midwest ISO footprint, standard monitoring channels used in West Planning Region, and other interested elements as provided by study participants. The large generation units consist of the generators with Pmax larger than 150 MW. The simulation results plot the voltages and angles. Besides this common channel file for all disturbances, some specific monitoring elements were added to different regions/control areas.

Description of Events Analyzed
The following disturbances were analyzed:

- System intact, 50 Category B, 139 Category C, and 79 Category D disturbances were analyzed. These disturbances were provided by TOs or selected from previous Midwest ISO and regional studies.
- 22 non-converged contingencies identified in MTEP07 ACCC and voltage study were also analyzed

6.2.2 Summary of Results

A 20 second steady state simulation under system intact condition for three planning regions shows the dynamic case shows no steady state oscillations or instability.

A total of 111 NERC Category A, B, C and D events were analyzed in West Region: 10 Category B, 80 Category C and 20 Category D. Six disturbances in West Region were found unstable/low damping in MTEP06 dynamic simulations. Two of unstable disturbances are in Midwest ISO footprint: one Category C disturbance and one Category D disturbance. The other four disturbances are not presented in this reported since the faults are not located in Midwest ISO Transmission Owners' areas.

A total of 68 NERC Category A, B, C and D events were analyzed in Central Region, as follows: 13 Category B, 11 Category C and 43 Category D. No disturbance in the Central region has been identified as producing unstable/low damping oscillation.

A total of 114 NERC Category A, B, C and D events were analyzed in East Region: 37 Category-B, 60 Category-C and 16 Category-D. Six disturbances of East region are found to be unstable/low damping in MTEP07 dynamic simulations: three Category C disturbances and three Category D disturbances.

The dynamic stability analysis of MTEP 07 is summarized in Table 6.2-3.

Table 6.2-3
Dynamic Stability Analysis Results for 2013 Summer Off-Peak Case

NERC Category	Disturbances Studied	Unstable Disturbances
A	1	0
B	60	0
C	151	3
D	79	4

A complete summary dynamic stability results is in Appendix D2. Note that Appendix D2 is considered Critical Energy Infrastructure Information (CEII), therefore, it is only available on MTEP FTP site to parties with Non-Disclosure Agreements with Midwest ISO.

6.2.3 Plan to Address Identified Issues

One project was developed to address one unstable issue in ATC LLC area.

6.2.4 Open Issues

There are no open Category A or B issues in the dynamic stability analysis. There are 3 potentially unstable Category C3 issues under review. Midwest ISO is working with Transmission Owners to confirm that these are valid issues after allowed system adjustments are made. There are 4 unstable Category D issues.

6.3 Voltage Stability Analysis

6.3.1 Analysis Performed

Steady state voltages at all 100 kV and above substations (69 kV in some Transmission Owner areas) outside low and high voltage criteria established by Transmission Operators in the Midwest ISO footprint are monitored in the MTEP AC contingency analysis process. This is one aspect of voltage analysis.

The purpose of this voltage stability analysis was to identify voltage constraints which precede thermal constraints, limiting transfers in the 5 year planning horizon and to identify "Soft Spots" or regions on the verge of voltage collapse, deprived of reactive resources under different transfer scenarios in the Midwest ISO footprint. Studying transfers beyond the contractual dispatch in the MTEP base case are considered economic transactions; therefore, identification of these transfer limits may not indicate a reliability issue. Some transfers may be applied into a system from external sources to simulate a load increase within a system. Such transfers may be seen as baseline reliability issues if limits lie well within a reasonable margin of error in load forecast with all internal sources already dispatched and depleted of reactive power in the contractual dispatch model. This implies that the internal system is essentially very close to the knee of voltage collapse curve in the base contractual model with very little reactive reserves remaining on its machines.

This analysis is not intended to establish actual operating boundaries for the study regions. However, the results of this study may be used to compare with near term summer assessment studies as well as a benchmark to compare with future MTEP voltage stability studies to monitor the change in these transfer limits.

A P-V study methodology was used for this analysis using the MTEP07 2013 Summer Peak model. The model had to be tuned for voltage stability due to solution anomalies. Since the analysis was limited to a summer peak starting dispatch, it does not encompass a wide array of off-peak high transfer scenarios.

Voltages at substations, reactive reserves at significant units and flows on known interfaces were monitored for critical contingencies under various transfer scenarios.

The analysis studied critical contingencies on various transfers either historically known to cause low voltages or based on stake holder input. The transfer scenarios simulated to study regions with voltage constraints could be broadly separated by the following states: Illinois, Indiana, Iowa, Michigan, Ohio and Wisconsin. The results are organized by study region below.

6.3.2 Wisconsin Study Region

Effects of HVDC converter and inverter reactive power consumption were excluded from this study and the DC line out of Arrowhead was replaced with a Gen-Load model with the generator and load not participating in the transfer.

MAPP to ATC Gen to Load

The following source and sink definitions were used:

- Source: MAPP is defined as Xcel Energy, Minnesota Power, Great River Energy, Otter Tail Power and WAPA (Generic Area Generation Scale).

- Sink: ATC load is defined as Alliant Energy-East, Wisconsin Power & Light, Wisconsin Electric Power Company, Wisconsin Public Service Corporation and Madison Gas & Electric Company (Generic Load Increase). Note UPPCO is not included.

The analysis results in transfer limit at 780 MW limited by double contingency: "KEA_G+GP_STK" (Loss of King - Eau Claire - Arpin 345 and Stone Lake - Gardner Park 345 kV lines and other lower kV lines as part of the operating guide). The pre-contingent flow on Eau Claire – Arpin line at this limit is 567 MW.

Since, the 345 kV double line outage King-Eau Claire-Arpin 345 and Stone Lake-Gardner Park 345, or Eau Claire-Arpin and Stone Lake-Gardner Park is not a valid single outage event after the Arrowhead-Stone Lake 345 kV line goes in service, the same analysis was run excluding the loss of Stone Lake - Gardner Park in the King-Eau Claire-Arpin 345 and Eau Claire-Arpin 345 contingencies. This would indicate the next operating limit for a single contingency if the Stone Lake SPS is no longer required. The resulting limit is at 1040 MW for the loss of Columbia unit 2 (635 MW). The pre-contingent flow on Eau Claire – Arpin line at this limit is 649 MW.

Details on worst buses, voltage constraints, P-V curves, interface flows and reactive reserves are documented in the Appendix D3.

MAPP to ATC Generation to Generation

The following source and sink definitions were used:

- Source: MAPP is defined as Xcel Energy, Minnesota Power, Great River Energy, Otter Tail Power and WAPA} (Generic Area Generation Scale)
- Sink: ATC Gen is defined as Alliant Energy-East, Wisconsin Power & Light, Wisconsin Electric Power Company, Wisconsin Public Service Corporation and Madison Gas & Electric Company (Specific Generation reduction). Note UPPCO is not included.

This transfer scenario is a variation of the prior transfer since the sink is simulated by scaling down generation as opposed to increasing load. The analysis results in transfer limit at 1260 MW limited by double contingency: "KEA_G+GP_STK" (Loss of King - Eau Claire - Arpin and Stone Lake - Gardner Park 345 kV lines and other lower kV lines as part of the Op-Guide). The pre-contingent flow on Eau Claire – Arpin line at this limit is 643 MW.

Since, the 345 kV double line outage King-Eau Claire-Arpin and Stone Lake-Gardner Park, or Eau Claire-Arpin and Stone Lake-Gardner Park are not valid single outage event after the Arrowhead-Stone Lake 345 kV line goes in service, the same analysis was run excluding the loss of Stone Lake - Gardner Park in the King-Eau Claire-Arpin and Eau Claire-Arpin contingencies. This would indicate the next operating limit for a single contingency if the Stone Lake SPS is no longer required. The resulting limit is at 1440 MW for the loss of Columbia unit 2 (635 MW). The pre-contingent flow on Eau Claire – Arpin line at this limit is 699 MW.

Details on worst buses, voltage constraints, P-V curves, interface flows and reactive reserves are documented in the Appendix D3.

MAPP to WUMS (Wisconsin Upper Michigan)

The following source and sink definitions were used:

- Source: MAPP is defined as Xcel Energy, Minnesota Power, Great River Energy, Otter Tail Power, Mid American, NPPD, OPPD, SPC and WAPA (Specific Units)

- Sink: WUMS is defined as Alliant Energy-Wisconsin Power & Light, Wisconsin Public Service Corporation, Madison Gas & Electric Company, Wisconsin Electric Power Company and Upper Peninsula Power Company (10% Load Scale and 80% Generic Area Generation Scale) and former ECAR {Allegheny Power, First Energy, American Electric Power, OVEC, Hoosier Energy, Duke Energy, DPL, Vectren, LGEE, BREC, DLCO, Indianapolis Power and Light, NIPSCO, Michigan Electric Transmission Company and EKPC} (Generic Area Generation Scale)

Reactive reserves were monitored for WPS resources zone. The analysis results in transfer limit at 1120 MW limited by double contingency: "KEA_G+GP_STK" (Loss of King - Eau Claire - Arpin and Stone Lake - Gardner Park 345 kV lines and other lower kV lines as part of the Op-Guide). The pre-contingent flow on Eau Claire – Arpin line at this limit is 560 MW. The pre-contingent flow on the Wempletown – Paddock 345 kV line at the limit is 1200 MW. The pre-contingent flow on the Wempletown – Rockdale 345 kV line at the limit is 420 MW.

Since, the 345 kV double line outage King-Eau Claire-Arpin and Stone Lake-Gardner Park, or Eau Claire-Arpin and Stone Lake-Gardner Park are not valid single contingencies after the Arrowhead-Stone Lake 345 kV line goes in service, the same analysis was run excluding the loss of Stone Lake - Gardner Park in the King-Eau Claire-Arpin and Eau Claire-Arpin contingencies. This would indicate the next operating limit for a single contingency if the Stone Lake SPS is no longer required. No transfer limit was found in this case with the transfer maxing out at 1890 MW.

Detailed P-V curves, interface flows and reactive reserves are documented in the Appendix D3.

ECAR to WUMS (Wisconsin Upper Michigan)

The following source and sink definitions were used:

- Source: ECAR is defined as Allegheny Power, American Electric Power, First Energy, DPL, Vectren, BREC and Michigan Electric Transmission Company (Specific Units)
- Sink: WUMS is defined as Alliant Energy-Wisconsin Power & Light, Wisconsin Public Service Corporation, Madison Gas & Electric Company, Wisconsin Electric Power Company and Upper Peninsula Power Company (Generic Area Generation Scale)

The first voltage constraint (69 kV voltages) for this interface was seen for a double contingency 1400 MW into the transfer. This is a not an issue of concern since our base model is a peak hour representation.

Details on thermal and voltage constraints, P-V curves, interface flows and reactive reserves are documented in the Appendix D3.

ECAR to ATC Load to Load

The following source and sink definitions were used:

- Source: ECAR is defined as American Electric Power and ComEd (Generic Load Reduction)
- Sink: ATC is defined as Alliant Energy-East, Wisconsin Power & Light, Wisconsin Electric Power Company, Wisconsin Public Service Corporation and Madison Gas & Electric Company (Generic Load Increase)

This transfer scenario as well as the next one is a variation of the previous transfer from ECAR to WUMS. The ECAR subsystem in this transfer is a subset of the previous transfer since it incorporates only AEP and ComEd. In addition the sink does not include Upper Peninsula Power Company. 1170 MW into the transfer, a double circuit tower outage fails to solve possibly indicating voltage stability issues. This contingency as seen also results in the largest drop in reactive reserves in Oak Creek Generation. Modal analysis shows low voltage MGE buses having the highest participation factors. This scenario shows potential voltage stability issues at very high transfer levels in our peak hour base case, therefore, transmission solutions to fix this economic issue will not be recommended at this time. However, this should be noted as a potential economic issue and monitored with future load growth in the area. Details on worst buses, voltage constraints, P-V curves, interface flows and reactive reserves are documented in the Appendix D3.

ECAR to ATC Load to Gen

The following source and sink definitions were used:

- Source: ECAR is defined as American Electric Power and ComEd (Generic Load Reduction)
- Sink: ATC is defined as Alliant Energy-Wisconsin Power & Light, Wisconsin Electric Power Company, Wisconsin Public Service Corporation and Madison Gas & Electric Company (Specific Generation reduction)

This transfer scenario is a variation of the prior transfer since the sink is simulated by scaling down generation as opposed to increasing load. 1320 MW into the transfer, a double circuit tower outage fails to solve, possibly indicating voltage stability issues. This contingency as seen also results in the largest drop in reactive reserves in Oak Creek Generation. Modal analysis shows low voltage MGE buses having the highest participation factors. Since, this scenario shows voltage stability issues at very high transfer levels in our peak hour base case, transmission solutions to fix this issue will not be recommended at this time. However, this should be noted as a potential issue and monitored with future load growth in the area. Details on worst buses, voltage constraints, P-V curves, interface flows and reactive reserves are documented in the Appendix D3.

6.3.3 Iowa Study Region

East to West

The following source and sink definitions were used:

- Source: East is defined as SIPC, EEI, ComEd, Alliant East, WPS, MGE, UPPC, CWLD, AMRN, IP, CILC, CWLP and WE (Part specific units and part generic area generation scale)
- Sink: West is defined as NPPD, OPPD and LES (Generation Scale)

There were no issues with this transfer.

West to East

The following source and sink definitions were used:

- Source: West is defined as NPPD, OPPD and LES (Generation Scale)
- Sink: East is defined as SIPC, EEI, ComEd, Alliant East, WPS, MGE, UPPC, CWLD, AMRN, IP, CILC, CWLP and WE (Generic Area Generation Scale)

There were no issues with this transfer.

North to South

The following source and sink definitions were used:

- Source: North is defined as XEL, GRE and DPC (Generation Scale)

- Sink: South is defined as AMRN, IP (Generic Area Generation Scale)

There were no issues with this transfer.

South to North across Tiffin Arnold Interface

The following source and sink definitions were used:

- Source: South is defined as AMRN, IP (Generic Area Generation Scale)
- Sink: North is defined as XEL, GRE and DPC (Generation Scale)

The following source and sink definitions were used:

- Source: South is defined as AMRN, IP (Specific Generation)
- Sink: North is defined as XEL, GRE and DPC(Generation Scale)

There were no issues with this transfer.

6.3.4 East Study Region

MAPP to ECAR

The following source and sink definitions were used:

- Source: MAPP is defined as Xcel Energy, Minnesota Power, Great River Energy, Otter Tail Power, Mid American, NPPD, OPPD, SPC and WAPA (Specific Units)
- Sink: ECAR is defined as Allegheny Power, First Energy, American Electric Power, OVEC, Hoosier Energy, Duke Energy, DPL, Vectren, LGEE, BREC, DLCO, Indianapolis Power and Light, NIPSCO, Michigan Electric Transmission Company and EKPC (Generic Area Generation Scale)

Voltage Stability Limits were identified 520 MW into the transfer. Modal analysis conducted to calculate bus participation factors indicates low voltage (34.5 kV) buses in northern Wisconsin. Further detailed look into these buses shows that these are radial 34.5 systems connected to Iron River 115 kV and Ironwood 115 kV buses. Detailed P-V curves, interface flows and reactive reserves are documented in the Appendix D3.

6.3.5 Michigan Study Region

South to METC

The following source and sink definitions were used:

- Source: South is defined as First Energy and American Electric Power (Specific Units)
- Sink: Michigan Electric Transmission Company (Generic Generation Reduction)

There were no issues with this transfer.

South to METC and ITC

The following source and sink definitions were used:

- Source: South is defined us First Energy, ComEd and American Electric Power (Specific Units)
- Sink: Michigan Electric Transmission Company and International Transmission Company (90% Generic Generation Reduction and 10% Load Increase)

There were no issues with this transfer.

6.3.6 Ohio Study Region

Two 345 kV capacitor projects: six 50 Mvar capacitor banks at Harding 345 kV bus (Expected In Service: 2008) and six 50 Mvar capacitor banks at Juniper 345 kV bus (Expected In Service 2009) were on in the base case with none of the banks switched in. Four of the six on both buses (200 Mvar each) were turned on in the base case by increasing the lower limit voltage threshold to 1 p.u.

South to North 1

The following source and sink definitions were used:

- Source: South is defined as Tennessee Valley Authority, American Electric Power and VAP (Part specific units and part generic area generation scale)
- Sink: North is defined as First Energy (10%) (Generic Area Generation Scale), METC-ITC (40%) (Generic Area Generation Scale) and NYISO-IESO (50%) (Generic Area Generation Scale)

First transfer limit is seen at 4500 MW into the transfer limited by a double contingency.

Details on monitored bus voltages, P-V curves and interface flows are documented in the Appendix D3.

South to North 2

The following source and sink definitions were used:

- Source: South is defined as Tennessee Valley Authority, American Electric Power and VAP (Part specific units and part generic area generation scale)
- Sink: North is defined as First Energy (10%) (Part Generic Load and part Generic Area Generation Scale), METC-ITC (40%) (Generic Area Generation Scale) and NYISO-IESO (50%) (Part Generic Load and part Generic Area Generation Scale)

For this scenario, transfer maxes out at 2800 MW.

Details on monitored bus voltages, P-V curves and interface flows are documented in the Appendix D3.

West to East 1

The following source and sink definitions were used:

- Source: West is defined as American Electric Power, Duke, Ameren, Illinois Power and ComEd (Specific units)
- Sink: East is defined as PJM, Penelec, METED, JCPL, PL, PECO, PSEG, BGE, PEPCO, AE, DPL, UGI, RECO (85% Generic Area Generation Scale) NEPOOL (10% Generic Area Generation Scale) and NYISO, IESO (5% Generic Area Generation Scale)

For this scenario, transfer maxes out at 3400 MW.

Details on monitored bus voltages, P-V curves and interface flows are documented in the Appendix D3.

West to East 2

The following source and sink definitions were used:

- Source: West is defined as American Electric Power, Duke, Ameren, Illinois Power and ComEd (Specific units)
- Sink: East is defined as PJM, Penelec, METED, JCPL, PL, PECO, PSEG, BGE, PEPCO, AE, DPL, UGI, RECO (85% Generic Area Generation Scale) NEPOOL (5% Generic Area Generation Scale), NYISO, IESO (5% Generic Area Generation Scale) and METC, ITC, First Energy (5% Generic Load Scale)

For this scenario, transfer maxes out at 3400 MW.

Details on monitored bus voltages, P-V curves and interface flows are documented in the Appendix D3.

South to First Energy Load

The following source and sink definitions were used:

- Source: South is defined as Tennessee Valley Authority, American Electric Power (Specific units)
- Sink: First Energy Load (Load Zone Scaled at 85% power factor)

This transfer is limited by a double contingency at 440 MW. It should be noted that the Harding and Juniper 300 Mvar 345 caps were turned on in the base case as in other transfers at 200 Mvar each.

The above contingency depletes significant VAR's in the Cleveland area. To test if additional VAR capacity in the area improves the transfer, a 600 Mvar fictitious SVC was placed at a 3rd major 345 source to Cleveland area: Hanna 345 kV substation (Harding and Juniper being the other two). The base case picks up about 500 Mvar's. This improves the voltages in the area increasing the transfer limit by 160 MW (at 600 MW limited by the same double contingency.

6.3.7 Indiana Study Region

South to North

The following source and sink definitions were used:

- Source: South is defined as TVA, SOCO and Entergy (Generic area generation scale)
- Sink: North is defined as First Energy, ComED (90% Generic Area Generation Scale) and METC, ITC (10% Generic Area Generation Scale)

There were no issues with this transfer.

West to East

The following source and sink definitions were used:

- Source: West is defined as ComEd, Ameren and Illinois Power (Generic area generation scale)
- Sink: East is defined as PJM, Penelec, METED, JCPL, PL, PECO, PSEG, BGE, PEPCO, AE, DP&L, UGI, RECO, IPRV, AP, DPL, DLCO, VAP and American Electric Power (Generic Area Generation Scale)

There were no issues with this transfer.

6.3.8 Illinois (CWLP) Study Region

South to North

The following source and sink definitions were used:

- Source: South is defined as TVA (Generic area generation scale)
- Sink: North is defined as ComED (Generic Area Generation Scale)

There were no issues with this transfer.

The following source and sink definitions were used:

- Source: South is defined as TVA (Generic area generation scale)
- Sink: North is defined as ComED (Area Load Scale)

There were no issues with this transfer.

West to East

The following source and sink definitions were used:

- Source: West is defined as Ameren and Illinois Power (Generic area generation scale)
- Sink: East is defined as American Electric Power (Generic Area Generation Scale)

There were no issues with this transfer.

The following source and sink definitions were used:

- Source: West is defined as Ameren and Illinois Power (Generic area generation scale)
- Sink: East is defined as American Electric Power (Generic Area Load Scale)

There were no issues with this transfer.

6.3.9 Summary of Voltage Stability Results

As documented above, some planned reactive power projects had to be turned on in the base model to help the voltage profiles. In some instances, reactive projects that may help the voltage profiles and increase transfer capabilities have been proposed. These results may be used as general guidelines of where reactive power projects help increase transfer capabilities.

The study did not find low voltage areas or voltage stability issues for critical contingencies in transfer scenarios that are close to the starting base load levels modeled in the MTEP07 2013 Summer Peak model. As a result of which at this time, none of the voltage issues can be categorized as baseline reliability issues.

6.4 Generator Deliverability Analysis

6.4.1 Analysis Performed

The Generator Deliverability analysis determines the ability of groups of generators in an area to operate at their maximum capability without being limited by transmission constraints, that is, without being bottled-up. This test is performed as part of the generator interconnection study process on new generators before granting Network Resource (NR) status. The generator is required to fix any transmission constraints limiting deliverability, in order to be treated as a Network Resource. A generator that is certified deliverable (not bottled-up) could be designated by any Load Serving Entity (LSE) within the Midwest Market Footprint to satisfy its Resource Adequacy requirement as specified in Module E of the Midwest ISO Energy Market Tariff.

The deliverability levels of already granted Network Resources may deteriorate overtime as a result of load growth and other changes to the transmission system. A Baseline Generator Deliverability Study is performed in order to identify and address any new transmission constraints to ensure ongoing deliverability of Network Resources. Also, baseline generator deliverability upgrades represent a reliability need to ensure the continued ability to count on Network Resources nominated to meet reserves.

The Baseline Generator Deliverability analysis was performed using the MTEP07 2013 Summer Peak model and by applying single transmission contingencies to deliverability dispatch patterns. The general generator deliverability study assumptions as described under Attachment B.6 of the Business Practices Manual for Generation Interconnection were used for the analysis. The deliverability was tested only up to the granted Network Resource levels of the Network Resource units modeled in MTEP07 2013 Summer Peak case.

6.4.2 Summary of Results

Table 6.4-1 below shows the list of constraints that limit deliverability of about 230 MW of Network Resources. See Appendix D4 for the detailed results with a list of impacted Network Resources.

Table 6.4-1: MTEP07 (2013 SUPK) Baseline Generator Deliverability Constraints Summary

Area	Overloaded Branch	Map ID	Contingency	Rating (MVA)	Pre-Shift %	Post-shift %	Solution
AMIL - Ameren Illinois	Rising - Goose Crk 345 kV line	1	Clinton - Maroa E - Goose Crk 345 kV	448	86%	104.6%	Proposed project in 2009 to increase the thermal capability of the Rising transformer from 450 MVA to 478 MVA (Project ID 1528)
AMIL - Ameren Illinois	Hennepin - Ottawa 138 kV line	2	Hennepin – Oglesby 138 kV	191	96%	103.8%	The limiting element in the 138 kV circuit is a terminal equipment at Hennepin, which could be upgraded to obtain full capability of the line conductor of 221 MVA by 2013.

Area	Overloaded Branch	Map ID	Contingency	Rating (MVA)	Pre-Shift %	Post-shift %	Solution
ALTE – Alliant Energy East	West Middleton-Timberline Tap 69-kV line	3	Verona - Oak Ridge 138 kV	84	94%	103.2%	West Middleton-Timberline Tap 69-kV line Possible solution - Uprate existing line to 230 degrees F line conductor operating temperature and replace terminal equipment to obtain a summer normal rating of 83 MVA and a summer emergency rating of 93 MVA.
WE – Wisconsin Energy	Presque Isle-Empire (Goose Lake) 138-kV line	4	Empire 2 - Empire 3 138 kV	166	88%	106.6%	Presque Isle-Empire (Goose Lake) 138-kV line Possible solution : Uprate existing line to 167 degrees F line conductor operating temperature and replace terminal equipment to obtain a summer emergency rating of 202 MVA (Require a summer emergency rating of 177 MVA to address the deliverability constraint).
XEL – Xcel Energy	Waconia -St Boni 69 kV line	5	Waconia -St Bonifacious 115 kV	58	88%	105.0%	Solution yet to be developed
MP – Minnesota Power	Fondulac - Hibbard 115 kV line	6	System Intact (Cat A)	40	86%	102.5%	Project being considered for this line
MP – Minnesota Power	Two Harbors - Waldo 115kV line	7	System Intact (Cat A)	112	88%	101.3%	Solution yet to be developed
MP – Minnesota Power	Silver Bay - Waldo 115 kV line	8	System Intact (Cat A)	112	97%	110.1%	Solution yet to be developed
GRE – Great River Energy	Pine City - Rock Lake 69 kV line	9	System Intact (Cat A)	24	0%	129.9%	Proposed to add second outlet
WPSC - Wolverine Power Supply	Bagley - Gaylord 69 kV line	10	System Intact (Cat A)	26	96%	107.3%	Proposed project to rebuild Bagley - Gaylord 69 kV line will address the issue. Project ID 1585

The description of Table 6.4-1 column headings is below.

- Overloaded Branch: An overload caused by "bottling-up" of generation. Deliverability was tested only up to the granted NR (Network Resource) levels of the existing and future NR units modeled in MTEP07 2013 case.
- Map ID: Use Map ID to find an approximate location of the overloaded element on Fig.6.4-1
- Contingency: The outage resulting in the overload. May be system intact, no outage.
- Rating: The rating of the overloaded element.
- %Pre-shift: Loading level on the constraint before ramping up generation in the "gen pocket"
- %Post-shift: Loading level on the constraint after ramping up generation in the "gen pocket"

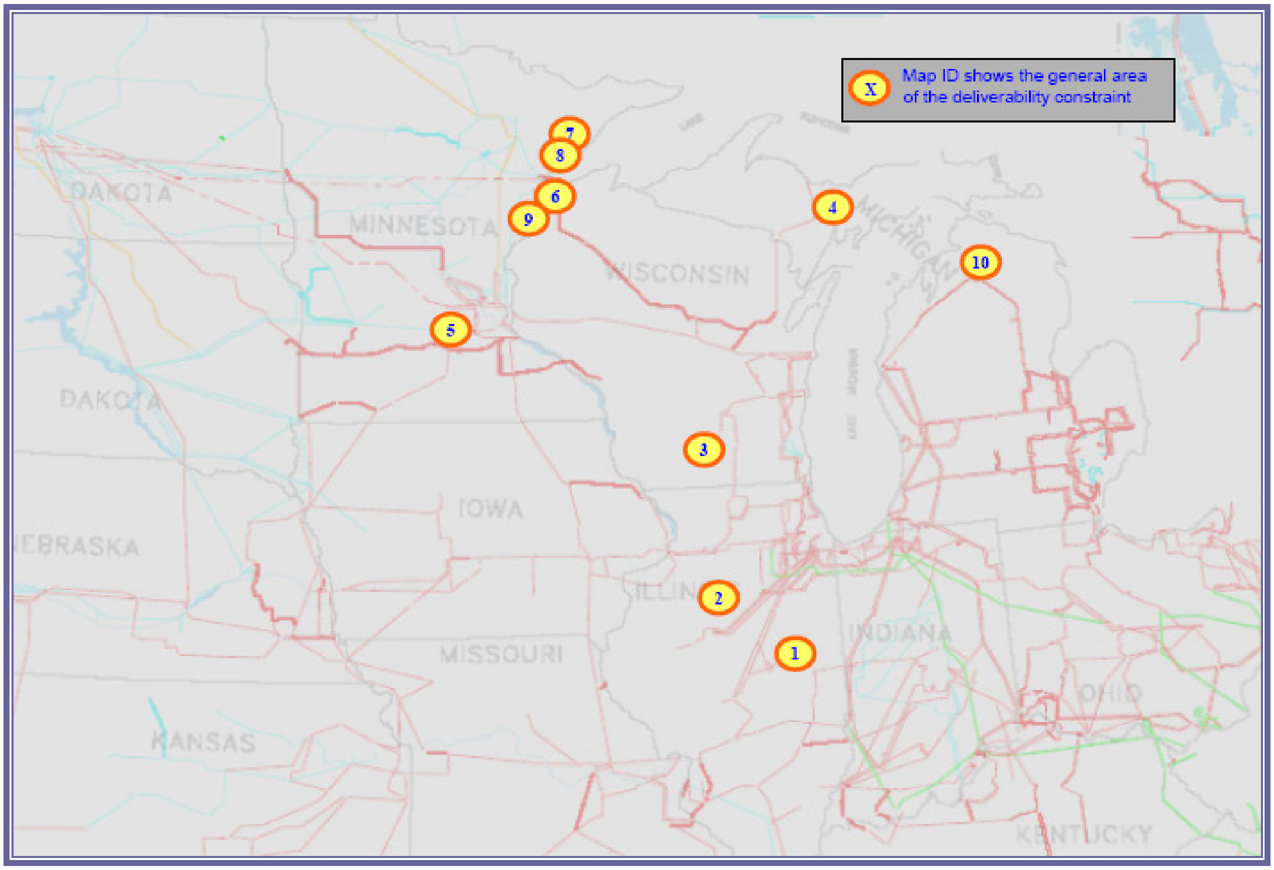

Figure 6.4-1:
General locations of 2013 SUPK Baseline Generator Deliverability Constraints

6.4.3 Plan to Address Identified Issues

As shown in Table 6.4-1 above, solutions have been identified to seven of the ten deliverability constraints. The Midwest ISO will work with the respective transmission owners to move these projects to Appendix A as Baseline Reliability Projects.

6.4.4 Open Issues

There are two 115 kV line constraints in Minnesota Power area and one 69 kV constraint in Xcel Energy area that need to be addressed (see Table 6.4-1 above). The Midwest ISO will work with the respective transmission owners to identify solutions to these remaining three issues.

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Section 7.0 MTEP07 Transmission Investment Summary

The present Midwest ISO Transmission System consists of approximately 53,000 miles of existing transmission lines over 100 kV and some 69 kV. This section provides a statistical overview of the expansion plans identified in the Midwest ISO Transmission Expansion Planning process. Appendix A lists the projects and associated facilities which are recommended to Midwest ISO Board of Directors as Planned. The projects in Appendix A have been analyzed and reviewed by Midwest ISO staff and the system needs driving the project have been documented. This level independent validation process is required with regional cost sharing of Baseline Reliability Projects via Attachment FF to the Energy Market Tariff. Projects in Appendix A are eligible for cost sharing, if the meet the requirements of the tariff. This section also discusses the projects in Appendix B. Appendix B contains projects which are Proposed or have not gone through the validation process by Midwest ISO staff to become recommended.

Although Midwest ISO has knowledge of planned facilities that are adjacent to the Midwest ISO system, those facilities are not quantified in this section. Such facilities are considered in ongoing model building, coordinating planning studies, and operating responsibilities of the Midwest ISO Reliability Authority (RA).

As discussed in Section 2, the Midwest ISO system is divided into three planning regions, shown below. Some of the information in this section will be summarize by Planning Region.

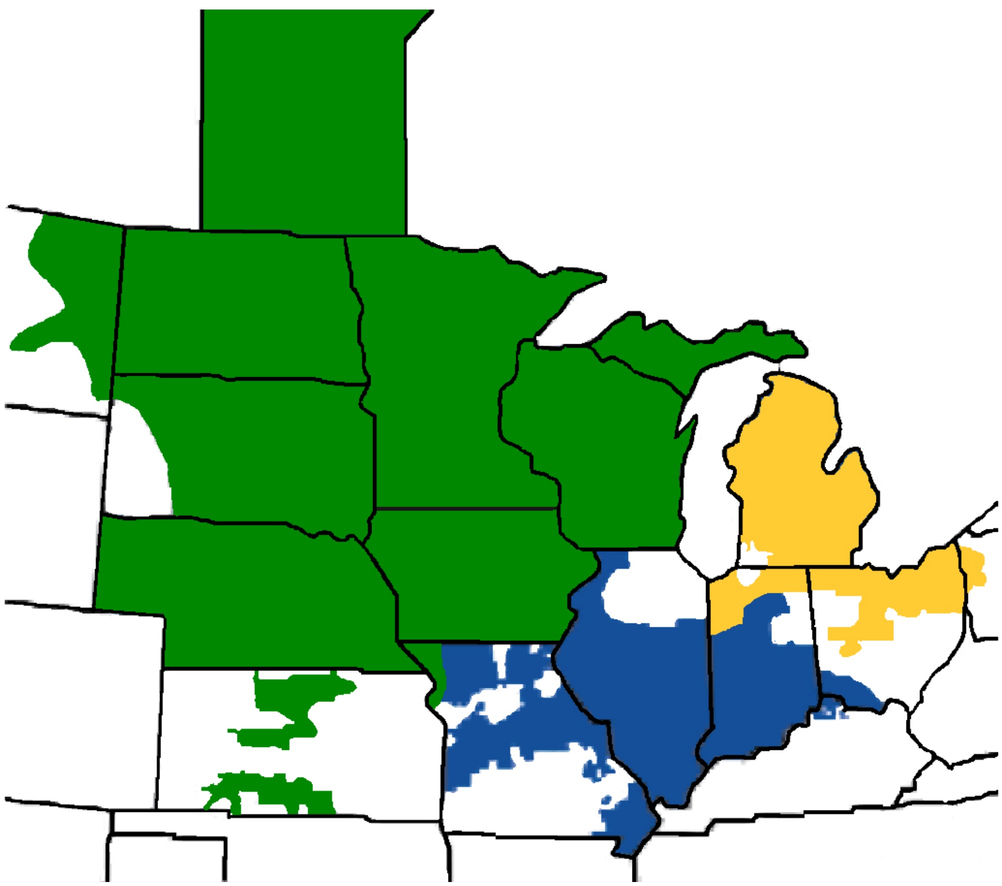

Figure 7.0-1
MTEP West, Central and East Planning Regions

7.1 Investment Summary

This section provides investment summaries of transmission system upgrades identified in MTEP 07. The total estimated cost of the projects in both Appendix A and Appendix B in the 2007 to 2013 study period is **$3.98 billion**. This is similar to the **$3.85 billion** that was estimated for the period 2006-2011 in MTEP 06. Appendix A contains $2.21 billion in investment, Appendix B contains $1.36 billion of investment, and Appendix C contains $405 million in investment through end of 2013.

The cumulative expected project spending over the 2007-2013 period is shown in the Figure below. This figure does not include the $420 million of projects which have gone into service in 2007.

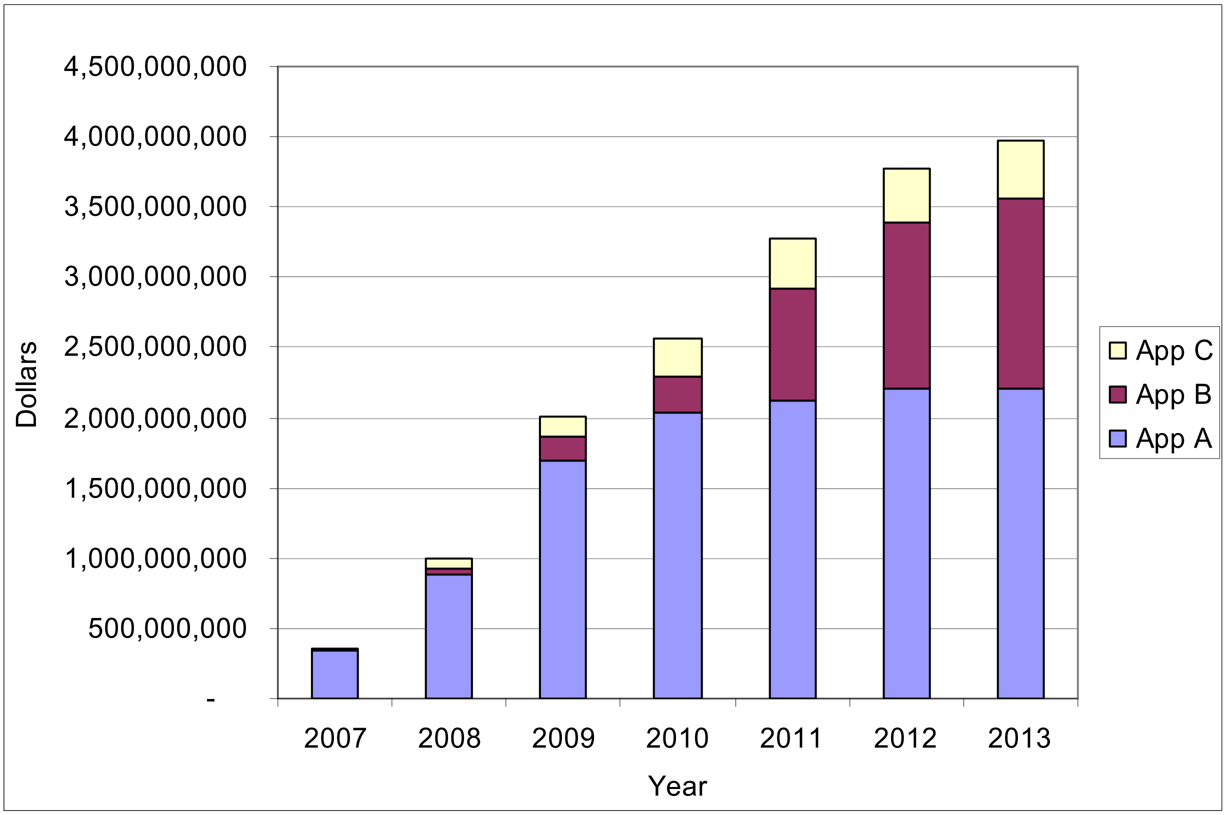

Figure 7.1-1
Cumulative Projected Investment by Year

The transmission investment by planning region through end of 2013 plan year is shown in the table below.

Table 7.1-2 Projected Transmission Investment by Planning Region

Region	Appendix A	Appendix B	Appendix C
Central	$409,335,000	$279,051,000	$61,977,000
East	$391,754,000	$96,569,000	$318,825,000
West	$1,412,532,000	$977,775,000	$30,299,000

Table 7.1-3 shows investment in Appendix A by preliminary cost allocation category and eligibility for cost sharing. See Section 2. 4 for a more complete discussion of cost sharing rules. Note that many large projects in the Western Region are not eligible for cost sharing as they precede Attachment FF or are part of the Attachment FF-1 “Exclude” list. The investment totals by year assume 100% of project investment occurs when the project goes into service. Since a project may have facilities going into service in multiple years, these numbers, therefore, appear lumpier than actual expenditures are expected to be.

Table 7.1-3
Appendix A Investment by Preliminary Allocation Category by Planning Region

Region	Share Status	Base. Rel.	Other	TAP: GIP	TAP: TDSP
Central	Excluded		$94,586,296		
	Not Shared	$14,040,406	$43,060,049		
	Not Shared (Pre-RECB1)		$96,631,400		
	Shared	$145,220,269		$15,416,300	
Central Total		$159,260,675	$234,277,745	$15,416,300	
East	Excluded		$9,733,166		
	Not Shared	$8,572,709	$63,166,000		$500,000
	Shared	$302,329,704		$7,832,616	
East	Total	$310,902,413	$72,899,166	$7,832,616	$500,000
West	Direct Assigned				$8,500,000
	Excluded		$272,752,056		
	Not Shared	$14,239,249	$221,076,545		$138,227,481
	Not Shared (Pre-RECB1)		$184,264,892		
	Shared	$370,252,726		$203,219,281	
West	Total	$384,491,975	$678,093,493	$203,219,281	$146,727,481
Grand Total		$854,655,063	$985,270,404	$226,468,197	$147,227,481

Further breakdown of the Appendix A data, as shown in Figure 7.1-4 reveals that new transmission build is largely concentrated in several states, namely Wisconsin, Minnesota and Michigan. Of the total investment, approximately $245 million represents projects that are new to Appendix A in MTEP 07. More than half of that value is represented by new projects in Minnesota. These geographic trends can be expected to change over time as existing capacity in other parts of the system are consumed and new build becomes similarly necessary in those areas.

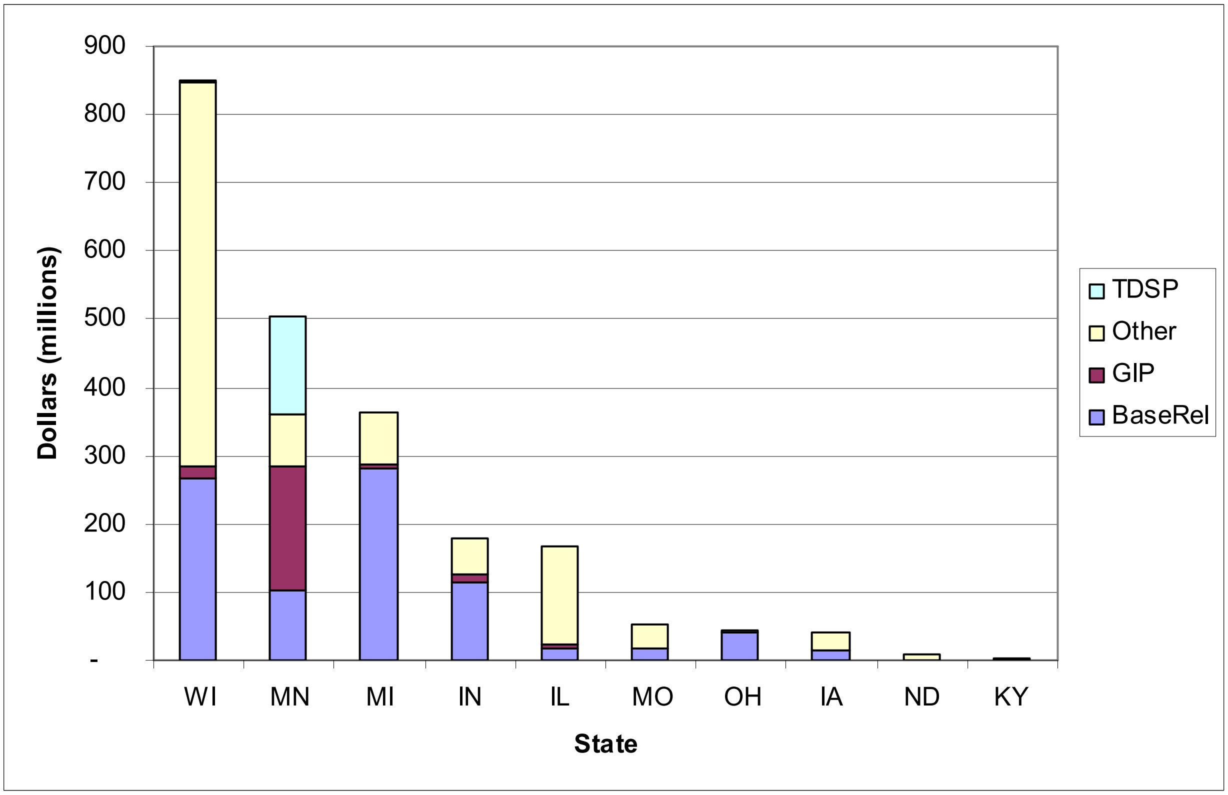

Figure 7.1-4
Appendix A Investment by Preliminary Allocation Category by State

7.2 Cost Sharing Summary

A total of $288 million of costs associated with Appendix A projects are reallocated between pricing zones, including $110 million to generation developers for their share of the Generator Interconnection Projects. Figure 7.2-1 provides the breakdown, by pricing zone, of project costs assigned to the zone after the cost allocation per Attachment FF, also referred to as Regional Expansion Criteria and Benefits (RECB) allocation. The blue bar represents the net unallocated project cost for the zone of projects proposed within the zone. In other words, the project cost less the portion of the cost allocated to other zones. The purple bar represents the portion of zonal costs that reflect allocations from projects outside the zone. Note that the chart excludes the portion assigned directly to generation developers. Additional details on cost allocation are in Appendix A-2.

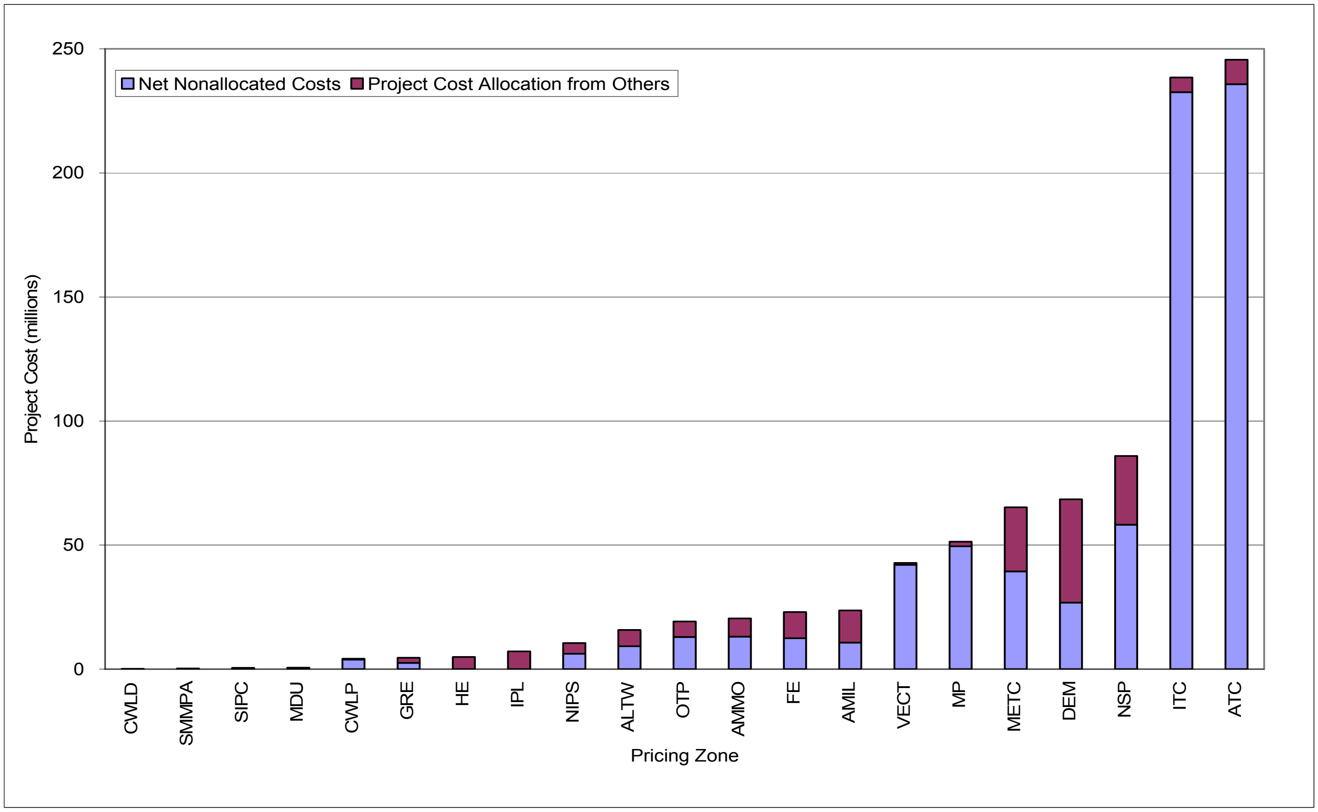

Figure 7.2-1
Projected Costs per Pricing Zone from Appendix A Projects after RECB Allocation

When the allocated portion of RECB costs are viewed as a percentage of the current net plant in service the percentages are relatively small. Entities that are undertaking proportionally large investments see the largest impact compared to the current net plant in service.

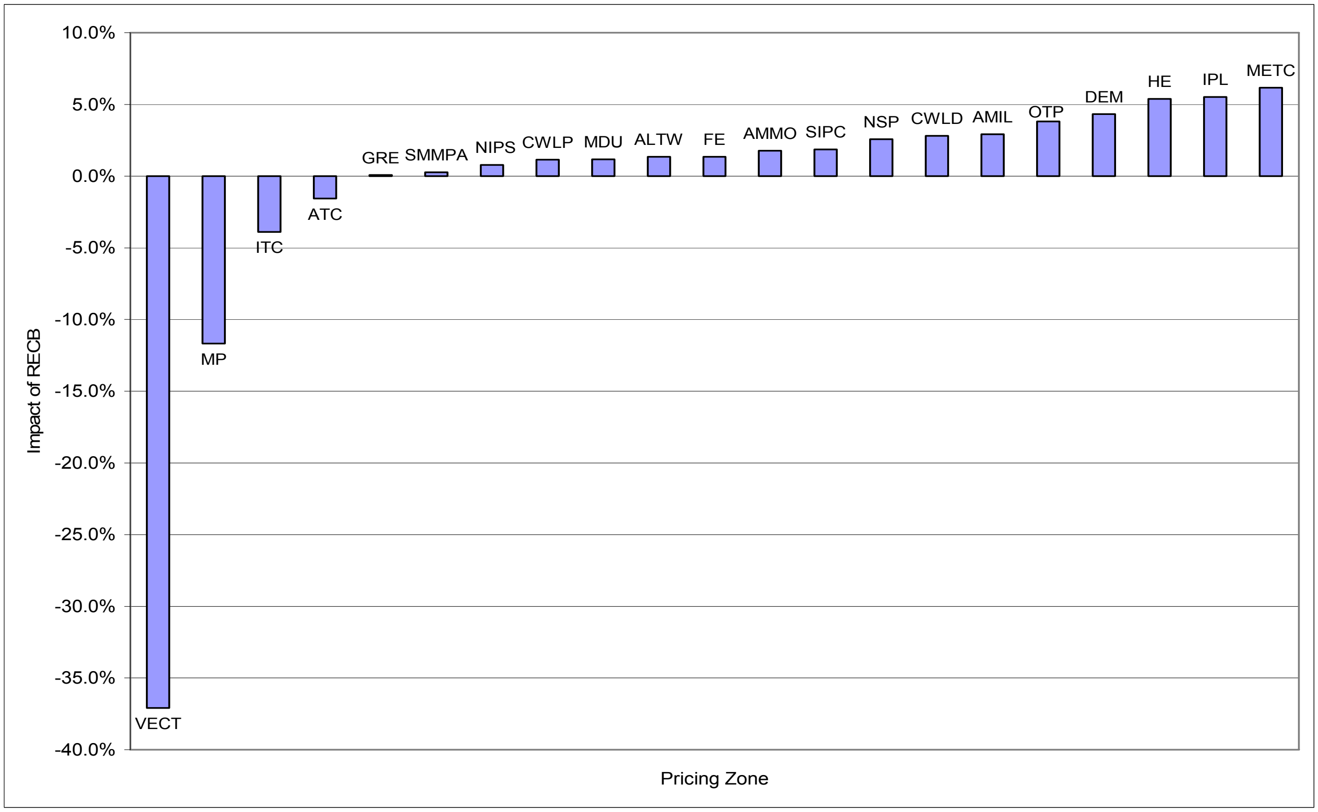

Figure 7.2-2
Appendix A RECB Allocation Impact on Net Plant in Service (as of July 2007)

7.3 Equipment Summary

There are approximately 4,600 miles of new or upgraded transmission lines in the 2007 through 2013 timeframe. There are an additional 1,000 miles of proposed transmission beyond the 2013 plan year in the 2014 to 2018 timeframe.

About 2,250 miles of transmission line *upgrades* are projected through 2013 which is about 4.2% of the approximately 53,000 miles of line existing higher voltage transmission throughout the Midwest ISO area. About 2,340 miles of transmission involving lines on *new* transmission corridors is also projected. The miles of transmission line by voltage class are shown in figure below.

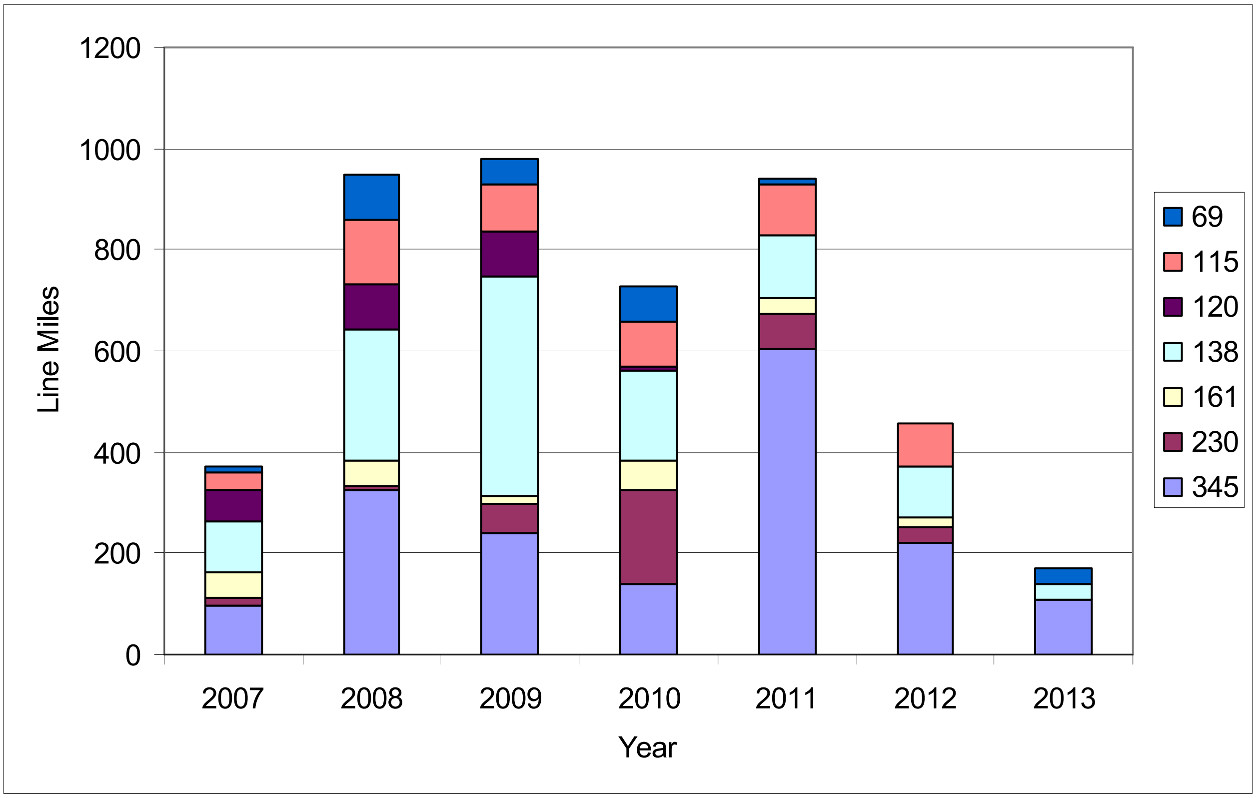

Figure 7.3-1
New or Upgraded Line Miles by Voltage Class in Kilovolts (kV)

The breakdown of these line miles by state, shows the greatest concentration of 345 kV lines planned for Minnesota and Michigan.

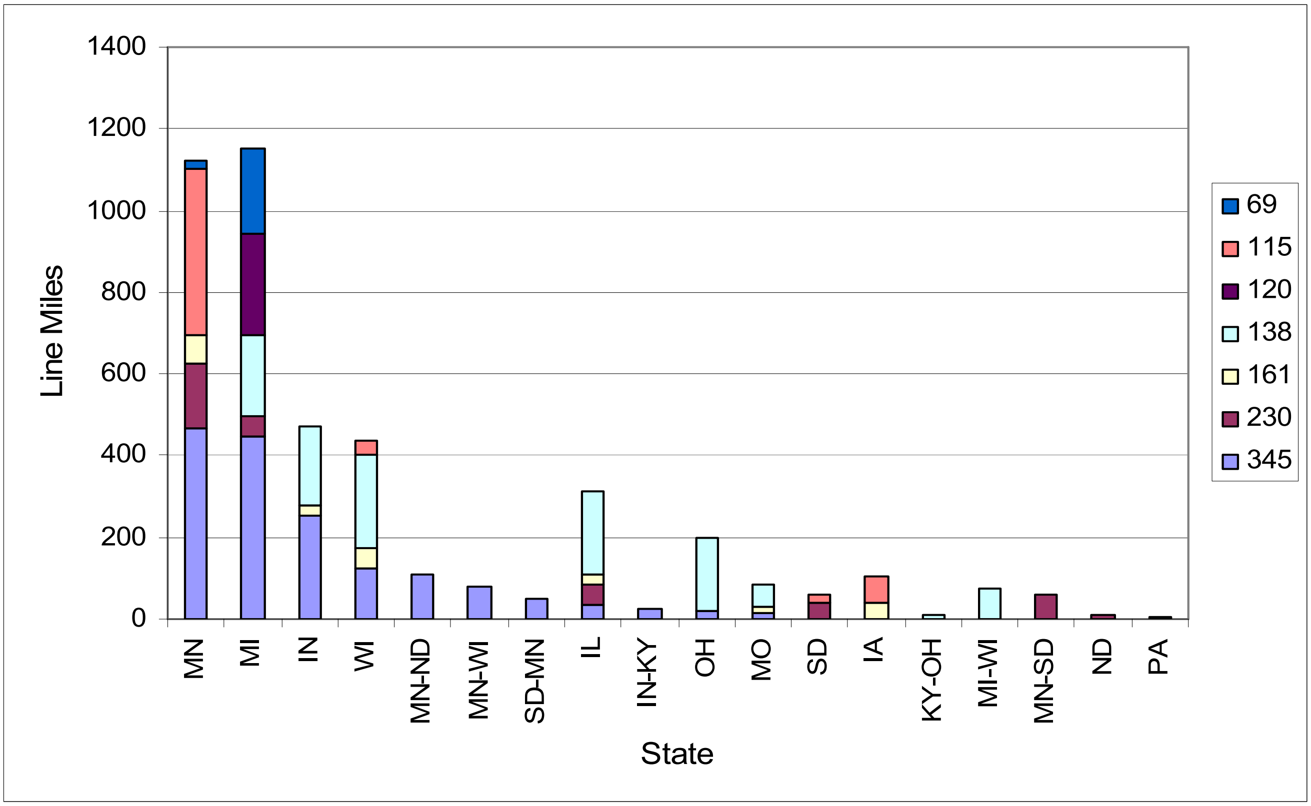

Figure 7.3-2
New or Upgraded Line Miles by Voltage Class and State

Appendices

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Project Information from Facility Table

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
A		**Appendix A**												A
A	West	ALTW	90	Emery-Lime Crk 161kV, Ckt 2	Emery - Lime Creek 161 ckt 2, Sum rate 326	IA		Other	Excluded	$8,000,000	6/1/2007	161		A
A	West	ALTW	1287	Replace Salem 345/161 kV transformer with 448 MVA unit	Replace Salem 345/161 kV transformer with 448 MVA unit	IA		BaseRel	Shared	$5,000,000	6/1/2008	345	161	A
A	West	ALTW	1288	Replace Hazleton 345/161 kV transformer #1 with 335 MVA unit	Replace Hazleton 345/161 kV transformer #1 with 335 MVA unit	IA		BaseRel	Shared	$5,000,000	6/1/2009	345	161	A
A	West	ALTW	1289	Marshalltown - Toledo - Belle Plaine - Stoney Point 115 kV line rebuild	Marshalltown - Toledo - Belle Plaine - Stoney Point 115 kV line will be rebuilt/upgraded between 2008 and 2011	IA		Other	Not Shared	$19,000,000	6/1/2010	115		A
A	West	ALTW	1342	Lewis Fields 161 kV substation which taps the SwampFX - Coggon 115 kV line	Build a new 161 kV substation Lewis Fields to be tapped to the 115 kV line Swamp Fox - Coggon at 5% distance via a new 161/115 kV transformer. Also build a new 161 kV line from Hiawatha to Lewis Fields	IA		BaseRel	Not Shared	$4,550,000	6/1/2011	161	115	A
A	West	ALTW	1471	G518	G518	MN		GIP	Shared	$125,000	5/1/2007	69		A
A	West	ALTW	1472	G536	G536	MN		GIP	Shared	$125,000	5/1/2007	69		A
A	West	ALTW	1473	Mason City Armor - Emery North 69 kV line	Mason City Armor - Emery North 69 kV line	IA		TDSP	Direct Assigned		6/1/2008	69		A
B>A	West	ALTW	1541	G530, 38518-01	Net: tap Jefferson Water Works 34.5 kV sub, install 2.4 MVAR cap bank near Panora substation	MN		GIP	Shared	$260,000	4/25/2007	34.5		A
A	Central	Ameren	78	Jefferson City Area Development	Moreau - Apache Flats 161 kV line, Loose Creek - Jefferson City 345 kV line, Jefferson City 345/161kV Transformer	MO		Other	Excluded	$17,620,500	6/1/2008	345	161	A
A	Central	Ameren	144	Crab Orchard - Marion South 138 kV	Crab Orchard - Marion South 138 kV - Reconductor line	IL		Other	Excluded	$1,557,100	6/1/2008	138		A
A	Central	Ameren	149	Mason-Sioux-7 345 kV	Mason-Sioux-7 345 kV - Breaker addition at Mason	MO		Other	Excluded	$799,000	6/1/2007	345		A
C>A	Central	Ameren	152	Big River-Rockwood 138 kV	Big River-Rockwood 138 kV - Construct new line	MO		BaseRel	Shared	$13,381,100	12/1/2010	138		A
A	Central	Ameren	153	Central-Watson-1 138 kV	CEE Tap - Watson section of Central-Watson-1 138 kV - Reconductor line	MO		Other	Not Shared	$277,200	6/1/2008	138		A
A	Central	Ameren	155	Joachim 345/138 kV	Joachim 345/138 kV - New Substation	MO		Other	Excluded	$13,345,100	6/1/2008	345	138	A
A	Central	Ameren	708	Casey-Breed 345 kV	Casey-Breed 345 kV Line - Reconductor river crossing	IL		Other	Excluded	$457,600	6/1/2007	345		A
A	Central	Ameren	712	Mason 345/138 kV Substation	Labadie-Mason-4 345 kV Terminal equipment replacement	MO		Other	Excluded	$312,900	12/1/2007	345		A
A	Central	Ameren	715	Wildwood-Gray Summit-1 138 kV	Wildwood-Gray Summit-1 138 kV - Reconductor line	MO		Other	Excluded	$132,700	6/1/2008	138		A
A	Central	Ameren	716	Wildwood-Gray Summit-2 138 kV	Wildwood-Gray Summit-2 138 kV - Reconductor line	MO		Other	Excluded	$132,700	6/1/2008	138		A
A	Central	Ameren	719	Labadie Plant	Labadie Plant - Replace 4-345 kV Breakers	MO		Other	Not Shared	$2,511,700	6/1/2009	345		A
C>A	Central	Ameren	783	Robinson-Marathon 138 kV Substation	Robinson-Marathon 138 kV Substation - Increase 18 MvarCapacitor bank to 36 Mvar	IL		BaseRel	Not Shared	$259,200	6/1/2007	138		A
A	Central	Ameren	857	Rush Island-Joachim 345 kV Line	Rush Island-Joachim 345 kV - Replace terminal equipment at Rush Island	MO		Other	Not Shared	$285,400	6/1/2008	345		A
A	Central	Ameren	858	Sioux-Huster-1 138 kV	Sioux-Huster-1 138 kV - Increase ground clearance on 6 miles of 795 kcmil ACSR	MO		BaseRel	Not Shared	$520,100	6/1/2007	138		A
A	Central	Ameren	859	Central-Watson-1 138 kV	Central-Watson-1 138 kV - Reconductor 5.1 miles 954 kcmil ACSR between Central and Twr. 55	MO		BaseRel	Not Shared	$2,681,600	6/1/2008	138		A
A	Central	Ameren	1241	Mattoon, West Wind Farm Connection	Install 138 kV Breaker at Mattoon, West Substation to connect Wind Farm	IL		Other	Not Shared	$659,400	3/1/2008	138		A
A	Central	AmerenCILCO	141	Duck Creek-Tazewell 345 kV	Duck Creek-Tazewell 345 kV - Convert bus duct to overhead	IL		Other	Excluded	$119,500	12/1/2007	345		A

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A	Central	AmerenCILCO	876	Tazewell 345/138 kV Substation	Tazewell 345/138 kV Substation - Replace 2000 A terminal equipment with 3000 A on line to Powerton	IL		Other	Not Shared	$1,203,300	6/1/2007	345		A
A	Central	AmerenIP	150	Prairie State Power Plant transmission outlet	Establish a new Prairie State 345 kV switchyard including a 6-p	IL		Other	Not Shared (Pre-RECB	$77,987,700	6/1/2008	345		A
A	Central	AmerenIP	725	LaSalle Area Development	N. LaSalle-Wedron Fox River 138 kV - 20 miles new line, 2-138 kV breakers at N. LaSalle, 1 138 kV Breaker at Wedron Fox River	IL		Other	Excluded	$21,357,530	12/1/2008	138		A
A	Central	AmerenIP	726	LaSalle Area Development	Ottawa-Wedron Fox River 138 kV - Construct 14 miles new 138 kV line, 1 new 138 kV breaker at Ottawa	IL		Other	Excluded	$8,962,967	12/1/2008	138		A
A	Central	AmerenIP	728	Wood River-Roxford 1502 138 kV line	Wood River-Roxford 1502 138 kV line - Reconductor	IL		BaseRel	Shared	$4,605,700	6/1/2008	138		A
A	Central	AmerenIP	732	S. Bloomington-State Farm 138 kV	S. Bloomington-State Farm 138 kV - Reconductor	IL		BaseRel	Not Shared	$1,085,900	12/1/2007	138		A
A	Central	AmerenIP	736	W. Tilton 138 kV Substation	W. Tilton 138 kV Substation - Install 138 kV breaker	IL		BaseRel	Not Shared	$2,658,600	12/31/2007	138		A
A	Central	AmerenIP	738	Latham-Lanesville 138 kV Line	138 kV Line 1342C tap - Line 1342A - Reconductor structure 423 to 467A	IL		Other	Excluded	$2,035,000	12/15/2007	138		A
A	Central	AmerenIP	739	Franklin County Power Plant Connection	Franklin County Power Plant Connection - Tap 345 kV Line 4561 Tap, and Install new 345 kV ring bus	IL		Other	Not Shared (Pre-RECB	$6,410,900	1/1/2009	345		A
A	Central	AmerenIP	865	Havana-Monmouth 138 kV River Crossing	Havana-Monmouth 138 kV Line 1362 - Rebuild river crossing	IL		Other	Not Shared	$2,674,600	6/1/2009	138		A
C>A	Central	AmerenIP	866	Latham 138 kV line termination	Latham Substation - Install 138 kV breaker for 'in-out' taps to 138 kV Line 1342, construct 0.38 miles 138 kV line for 'in-out' connections	IL		BaseRel	Not Shared	$1,494,400	6/1/2007	138		A
A	Central	AmerenIP	869	Sidney-Mira Tap 138 kV	Sidney-Mira Tap 138 kV - Reconductor 2 miles 795 kcmil ACSR	IL		BaseRel	Not Shared	$634,300	9/1/2007	138		A
C>A	Central	AmerenIP	870	Sidney-Paxton 138 kV	Sidney-Paxton 138 kV - Reconductor 18 miles of 350 kcmil Cu	IL		BaseRel	Shared	$5,878,500	6/1/2008	138		A
A	Central	AmerenIP	873	Baldwin Plant 345 kV Switchyard	Replace 6-345 kV breakers with breakers having 3000 A continuous capability	IL		Other	Not Shared (Pre-RECB	$12,232,800	1/31/2009	345		A
A	West	ATC LLC	1	Arrowhead-Gardner Park 345 kV	Arrowhead - Gardner Park 345 kV line	WI	MN	Other	Excluded	$157,519,173	6/30/2008	345	230	A
A	West	ATC LLC	101	Kelly-Whitcomb 115 kV uprate	Kelly - Whitcomb 115 ckt , Sum rate 241	WI		Other	Excluded	$1,900,000	6/1/2008	115		A
A	West	ATC LLC	175	Ellinwood-Sunset Point 138 kV	Ellinwood - Sunset Point 138 ckt , Sum rate	WI		Other	Excluded	$2,500,000	11/1/2007	138		A
A	West	ATC LLC	177	Gardner Park-Highway 22 345 kV line projects	Construct Gardner Park-Highway 22 345 kV line and Construct new Highway 22 345 kV substation	WI		Other	Not Shared (Pre-RECB	$128,900,000	12/1/2009	345		A
A	West	ATC LLC	339	Lake Mills Transmission-Distribution interconnection	Construct a Jefferson-Lake Mills-Stony Brook 138 kV line Uprate Rockdale to Jefferson 138 kV line Uprate Rockdale to Boxelder 138 kV line Uprate Boxelder to Stonybrook 138 kV line	WI		Other	Excluded	$20,450,000	5/31/2009	138		A
A	West	ATC LLC	345	Morgan - Werner West 345 kV line (includes Clintonville-Werner West 138)	Morgan - Werner West 345 kV line, Clintonville - Werner West 138 kV line primarily on 345 kV line structures, and terminate the existing Werner - White Lake 138 kV line at the Werner West switching station	WI		BaseRel	Shared	$141,290,700	12/1/2009	345		A

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B>A	West	ATC LLC	347	Rubicon-Hustisford-Hubbard 138 kV	Construct a Rubicon-Hustisford 138 kV line, Rebuild Hustisford-Hubbard 69 kV to 138 kV, Construct 138/69 kV substation at a site near Hubbard and install a 138/69 kV transformer	WI		Other	Not Shared	$20,372,000	6/1/2008	138	69	A
A	West	ATC LLC	352	Cranberry-Conover 115 kV and Conover-Plains conversion to 138 kV	Construct Cranberry-Conover 115 kV line, Rebuild/convert Conover-Plains 69 kV line to 138 kV, Construct 138 kV bus and install 138/115 kV 150 MVA and 138/69 kV 60 MVA transformers at Conover, Construct 138 kV bus and install 60 MVA transformer at Bobcta, Relocate Iron River substation (Iron Grove), Construct 138 kV bus and install a 138/69 kV, 60 MVA transformer at Iron Grove	WI		BaseRel	Shared	$114,485,000	12/31/2009	138	115	A
A	West	ATC LLC	566	Plymouth T-D interconnection	Forest Junction / Charter Steel to Plymouth 138 kV line and T-D substation. Construct 1.3 mile double circuit from Plymouth municipal utility to existing line.	WI		Other	Excluded	$2,500,000	10/15/2007	138		A
A	West	ATC LLC	567	North Appleton-Lawn Road-White Clay 138 kV uprate	North Appleton - Lawn Road - White Clay 138 kV line upgrade. This project increases line clearance on the 30 mile line.	WI		Other	Excluded	$600,000	12/1/2007	138		A
A	West	ATC LLC	568	North Lake Geneva - White River 138 kV line	North Lake Geneva - White River 138 kV line	WI		Other	Excluded	$1,250,000	6/1/2012	138		A
A	West	ATC LLC	570	Rock River-Bristol-Elkhorn conversion to 138 kV	Rock River - Bristol - Elkhorn conversion to 138 kV	WI		Other	Excluded	$15,063,960	6/1/2009	138		A
A	West	ATC LLC	571	North Madison-Waunakee 138 kV line	New North Madison - Huiskamp 138 kV line and a new 138/69 kV substation near Huiskamp including a 100 MVA 138/69-kV transformer	WI		Other	Excluded	$8,700,000	6/1/2008	138		A
A	West	ATC LLC	572	Menominee 138/69 kV transformer	Loop West Marinette - Bay de Noc 138 kV line into Menominee. Total project cost $2,000,000.	WI		Other	Excluded	$3,915,000	11/1/2008	138	69	A
A	West	ATC LLC	877	Elm Road (Oak Creek) Generation Related Additions	Reconductor Oak Creek-Ramsey 138 kV line (2009), Reconduc	WI		Other	Not Shared (Pre-RECB	$44,706,194	6/1/2010	345	138	A
B>A	West	ATC LLC	880	Lost Dauphin-North Appleton-Mason Street 138 kV uprates	Lost Dauphin-North Appleton-Mason Street 138 kV uprates	WI		TDSP	Direct Assigned	$3,300,000	6/1/2008	138		A
B>A	West	ATC LLC	882	Ontonagon 16.32 MVAR capacitor bank	Ontonagon 16.32 MVAR capacitor bank	MI		BaseRel	Not Shared	$1,200,000	6/1/2007	138		A
B>A	West	ATC LLC	886	North Lake (Cedar) sub relocation	North Lake (Cedar) substation relocation	MI		Other	Not Shared	$7,300,000	6/1/2008	138		A
A	West	ATC LLC	1256	Paddock - Rockdale 345kV	Paddock - Rockdale 345kV circuit #2 and supporting projects of lower voltage levels	WI		Other	Not Shared	$126,500,000	4/1/2010	345		A
B>A	West	ATC LLC	1267	New Oak Ridge-Verona 138-kV line and a 138/69-kV transformer at Verona	Construct new Oak Ridge-Verona 138-kV line and install a 138/69-kV transformer at Verona	WI		Other	Not Shared	$22,100,000	6/1/2010	138	69	A
B>A	West	ATC LLC	1281	Uprate the Portage to Trienda X-19 to 293/339 MVA	Uprate the Portage to Trienda X-19 to 293/339 MVA	WI		BaseRel	Not Shared	$1,031,249	6/1/2008	138		A
B>A	West	ATC LLC	1283	Retap CT at Freeman for new ratings of 195 SN/202 SE after confirmation of 167 deg F line clearance	Retap CT at Freeman for new ratings of 195 SN/202 SE after confirmation of 167 deg F line clearance	WI		BaseRel	Not Shared	$5,000	6/1/2008	138		A

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A	West	ATC LLC	1453	St Lawrence - Pleasant Valley - Saukville 138 kV line reconductor	St Lawrence - Pleasant Valley - Saukville 138 kV line reconductor	WI		BaseRel	Shared	$9,600,000	6/1/2008	138		A
A	West	ATC LLC	1461	G376, 37395-03, Green Lake Energy	Net: loop into existing substation, install 138 kV equipment at Green Lake Sub, replace 69 kV circuit breaker at Wautoma sub.	WI		Other	Not Shared (Pre-RECB 1)	$2,314,698	10/20/2006	138	34.5	A
A	West	ATC LLC	1463	G384	Net: new two breaker 138 kV substation, loop line Y-51 into the substation, perform a relay replacement for Kewaunee sub 138 kV line Y-51 to Shoto sub.	WI		Other	Not Shared (Pre-RECB 1)	$3,268,000	10/20/2006	138		A
A	West	ATC LLC	1470	G483	50 MW wind farm at Whistling Wind 69 kV sub	WI		GIP	Shared	$7,538,732	11/5/2006	69		A
C>A	West	ATC LLC	1616	G507	98 MW wind farm at Cedar Ridge 138kV sub	WI		GIP	Shared	$343,000	12/28/2007	138		A
C>A	West	ATC LLC	1617	G527	280 MW coal unit at Nelson Dewey 161 kV sub	WI		GIP	Shared	$11,074,000	6/1/2011	161		A
C>A	Central	CWLP	1620	G412 - Dallman 4 Unit	Network Upgrades associated with 200 MW Dallman #4 in Springfield, Illinois	IL		GIP	Shared	$7,829,300	1/1/2010	138		A
A	Central	DEM	42	Bedford to Seymour 13829 Reconductor	Reconductor 13829 line from Bedford - Shawswick - Pleasant Grove - Airport Road Jct - Seymour.	IN		Other	Excluded	$8,860,499	6/1/2010	138		A
A	Central	DEM	91	Hillcrest 345/138	Construct new 345/138 kV Hillcrest substation. Tap Suart to Foster 345kV line. Construct new 138kV line from Eastwood to Hillcrest. Replace 345kV relays at Stuart and Foster. Replace 138kV relays at Brown and Ford Batavia.	OH		BaseRel	Shared	$17,687,496	6/1/2008	345	138	A
A	Central	DEM	200	W Laf Purdue to Purdue NW 138kV Upgrate and Switch replacement	Upgrade 138kV switches at West Lafayette Purdue and uprate conductor to 100C.	IN		Other	Excluded	$9,878	6/1/2008	138		A
A	Central	DEM	618	Beckjord 138 Reconfigure	Rebuild the Beckjord 138 Substation so it can be tied together under normal conditions.	OH		Other	Excluded	$1,738,266	12/31/2009	138		A
A	Central	DEM	619	IPL Petersburg 345 Breaker	Complete breaker and half scheme at Petersburg Plant. IPL total estimate 1,100,000. 200,000 is Cinergy share of project.	IN		Other	Excluded	$200,000	6/1/2008	345		A
A	Central	DEM	624	Cloverdale to Plainfield 138 Lightning Protection	Upgrade static and grounding on the Cloverdale to Plainfield South 138kV circuit.	IN		Other	Excluded	$1,816,905	12/31/2008	138		A
A	Central	DEM	627	Kenton to West End New 138 Circuit	Construct new 138kV line from Kenton to West End.	KY	OH	Other	Excluded	$1,980,041	6/1/2009	138		A
A	Central	DEM	632	Gallagher to HE Georgetown 138kV Reconductor	Reconductor section of the 13885 circuit from Gallagher to HE Georgetown.	IN		Other	Excluded	$1,065,110	6/1/2009	138		A
A	Central	DEM	807	Dresser Bk 1&2 Limiting Equipment	Replace 138kV breakers and switches to achieve full transformer rating.	IN		BaseRel	Not Shared	$395,678	6/1/2009	345	138	A
A	Central	DEM	839	Crawfordsville 69kV Cap	Add 28.8 MVAR 69kV capacitor at Crawfordsville.	IN		BaseRel	Not Shared	$500,000	11/2/2007	138		A
A	Central	DEM	849	Peabody Jct 600A Switches	Replace Peabody Jct 600A switches with 1200A switches.	IN		Other	Not Shared	$318,341	12/31/2007	138		A
A	Central	DEM	851	Laf Cumberland to Laf AE Staley 138 Reconductor	Reconductor section of 13806 circuit with 954ACSR 100C.	IN		BaseRel	Not Shared	$349,357	6/1/2011	138		A
C>A	Central	DEM	852	Crawfordsville to Tipmont Concord to Lafayette SE 138 Reconductor	Reconductor 13819 circuit with 954ACSR 100C.	IN		BaseRel	Shared	$7,267,473	12/31/2009	138		A
A	Central	DEM	1193	Nickel	Extend 5680 through new Nickel 138/12 sub to be built on development property.	OH		Other	Not Shared	$150,377	6/1/2009	138		A
A	Central	DEM	1198	Bedford Switch Automation	Add motors and automation to the 34506 and 34521 line switches.	IN		Other	Not Shared	$152,390	6/1/2008	345		A

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A	Central	DEM	1199	Dresser to Water St 100C Urate	Uprate 13868 conductor to 100C operating temperature from Dresser to S 1st St to Water St. New limit 1200A terminal equipment.	IN		BaseRel	Not Shared	$20,000	6/1/2010	138		A
A	Central	DEM	1200	Speed Bk3 Limiting Equipment	Upgrade 2000A 138kV breaker & switch and any other Bk3 limiting equipment. Replace any equipment that would limit the 345/138 xfr to less than the hot spot rating of 520 MVA.	IN		BaseRel	Not Shared	$173,193	6/1/2010	345	138	A
A	Central	DEM	1244	Cayuga to Frankfort 23013 Wave Trap Upgrade	Upgrade wave traps at Cayuga and Frankfort to increase line rating to 797 MVA.	IN		BaseRel	Not Shared	$167,560	6/1/2011	230		A
A	Central	DEM	1246	Five Points 23030 Wave Trap	Replace 800A wave trap with a 2000A wave trap. Increase line rating for Five Points to Geist 230kV line.	IN		BaseRel	Not Shared	$24,038	6/1/2011	230		A
A	Central	DEM	1247	Greentown to Peru SE 23021 uprate to 100C	Upgrade Greentown to Peru SE 230kV line to 100C operating temperature.	IN		BaseRel	Not Shared	$28,403	6/1/2011	230		A
A	Central	DEM	1251	Kokomo Highland Park to Noblesville 23008 Wave Trap Upgrade	Replace 800A wave traps with 2000A wave traps at Kok HP and Noblesville. Increase 230kV line rating from Kok HP to Carmel 146th St Jct to Noblesville.	IN		BaseRel	Not Shared	$24,038	6/1/2011	230		A
A	Central	DEM	1253	Noblesville 23007 Wave Trap	Replace 800A wave trap with a 2000A wave trap. Increase line rating for Noblesville to Geist 230kV line.	IN		BaseRel	Not Shared	$24,038	6/1/2011	230		A
A	Central	DEM	1254	Charletown to CMC new 138kV line	Construct 8.5 mi. of 138kV line from Charlestown to CMC.	IN		Other	Not Shared		12/31/2009	138		A
A	Central	DEM	1262	HE Durgee Rd	HE 138/12 kV substation.	IN		Other	Not Shared	$227,341	6/1/2008	138		A
B>A	Central	DEM	1263	G431 - Edwardsport	Edwardsport 420 MW: Network Upgrades associated with G431 generator interconnection request	IN		GIP	Shared	$7,587,000	5/30/2011	345		A
A	East	FE	615	Gallion Transformers #3 and #4 345 kV Circuit Breaker Addtion	Add 345kV breaker to complete 345kV ring-bus as well as extend 138kV bus to include another breaker string to the existing breaker-and-a-half scheme.	OH		Other	Excluded	$1,815,566	11/1/2007	138		A
A	East	FE	890	North Medina 345/138 kV Substation	Add a new 345/138kV substation at the junction of the Star-Carlisle 345kV and Star-West Akron #2 138kV lines	OH		BaseRel	Shared	$11,840,000	6/1/2008	345	138	A
A	East	FE	1326	Add Capacitor Banks at Harding and Juniper 345 kV substations	Addtion of a 300 Mvar capacitor bank at the Harding 345 kV bus in 2008 and Addtion of a 300 Mvar capacitor bank at the Juniper 345 kV bus	OH		BaseRel	Shared	$7,000,000	6/1/2008	345		A
A	East	FE	1327	Babb - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$873,300	6/1/2009	138		A
A	East	FE	1328	Barberton - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$677,600	6/1/2010	138		A
A	East	FE	1329	West Akron - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$257,000	6/1/2010	138		A
A	East	FE	1330	South Akron - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$526,288	6/1/2007	138		A
A	East	FE	1331	East Akron - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$305,000	6/1/2011	138		A
A	East	FE	1332	Cloverdale - Install 138 kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH		BaseRel	Not Shared	$632,021	6/1/2008	138		A
A	East	FE	1333	Brookside -Add 138kV Cap Banks	Add 2 - 50 MVAR Cap Bank with 1 - 138 kV Switcher	OH		BaseRel	Not Shared	$1,000,200	6/1/2010	138		A
A	East	FE	1334	Longiew -Add 138kV Cap Bank	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Switcher	OH		BaseRel	Not Shared	$523,800	6/1/2010	138		A
A	West	GRE	599	Crooked Lake - Enterprise Park 115 kV line	Crooked Lake - Enterprise Park 115 kV line	MN		Other	Excluded	$3,600,000	6/1/2009	115		A
A	West	GRE	600	Baxter - Southdale 115 kV line	Baxter - Southdale 115 kV line	MN		Other	Excluded	$3,500,000	12/1/2008	115		A
A	West	GRE	601	Mud Lake - Wilson Lake 115 kV line	Mud Lake - Wilson Lake 115 kV line	MN		Other	Excluded	$6,000,000	12/1/2008	115		A

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A	West	GRE	1026	Linwood 230-69 kV transformer	Required for TSR A125 and A130	MN		TDSP	Direct Assigned	$5,000,000	6/1/2008	230	69	A
A	West	GRE	1459	G351, 37804-01, G352, 37804-02	Net: new Dakota County substation will be located between NSP Blue Lake and Prairie Island Substations on the 345 kV line 0976	MN		GIP	Shared	$8,935,288	5/1/2010	345		A
A	Central	HE	204	Tapline 138 to Buena Vista, Batesville, & North Charleston	Buena Vista-Tapline 138, Batesville-Tapline 138, North Charleston-Tapline 138	IN		Other	Not Shared	$1,850,000	6/1/2009	138	13	A
A	Central	HE	1318	Decatur County Switch Station (DCSS)	161/138kV Switching Station w/138kV Ring Bus	IN		Other	Not Shared	$7,000,000	9/1/2007	161	138	A
A	Central	HE	1319	Decatur County Switch Station Tap	138kV Taplines from Cinergy 138kV Transmission	IN		Other	Not Shared	$500,000	9/1/2007	138		A
A	Central	HE	1320	Greensburg Honda Subs & Tap Lines	Two 138/12.47kV substations and tap lines from DCSS	IN		Other	Not Shared	$9,250,000	9/1/2007	138	12.5	A
A	Central	HE	1321	Napoleon to DCSS Transmission Project	161kV Transmission from Napoloen to DCSS, 30 MVAR Cap	IN		Other	Not Shared	$8,000,000	9/1/2008	161		A
A	Central	HE	1322	Owensville Primary Substaton	138/69kV Primary Station at Owensville	IN		Other	Not Shared	$8,000,000	4/1/2008	138	69	A
A	Central	IPL	40	Cumberland-Julietta-Indian Crk 138kV Line	Add new 138kV Line from Cumberland to Julietta to Indian Creek	IN		Other	Excluded	$5,000,000	6/1/2008	138		A
A	Central	IPL	893	North 138 kV 150 MVAR Capacitor	Capacitor Bank SizeUpgrade: North 138 kV 100 MVAR To 150 MVAR	IN		BaseRel	Not Shared	$300,000	6/1/2009	138		A
A	Central	IPL	895	Georgetown To Northeast 138kV Loop-In	Loop Georgetown to Northeast 138kV Line Into North Substation	IN		BaseRel	Not Shared	$2,700,000	12/1/2007	138		A
A	East	ITC	518	Bismark-Golf	Bismark-Golf 120 kV line: create a 120 kV station at Golf and build a new 120 kV line from Bismarck to Golf.	MI		Other	Excluded	$4,000,000	10/31/2007	120		A
A	East	ITC	686	Majestic 345/120 kV switching station	Create a Majestic-Madrid 120 kV circuit by un-six wiring the existing Majestic-Madrid 345 kV circuit and connecting the available conductor to a new 120 kV bus and position off the Madrid 120 kV bus and the new 120 kV substation via a 345/120 kV transformer at the Majestic station. Poroject also requiresbus expansions at both Madrid 120 kV and 345 kV stations	MI		BaseRel	Shared	$6,200,000	12/31/2007	120		A
A	East	ITC	692	Bismark-Troy 345 kV line	Creates a Bismarck-Troy 345 kV line with a Troy 345/120 kV transformer.	MI		BaseRel	Shared	$150,000,000	12/31/2009	345	120	A
A	East	ITC	905	Marysville Decommissioning	Decommission Marysville Station, expand Bunce Creek Station creating new Bunce Creek - Cypress, Bunce Creek - Menlo, Bunce Creek - Wabash 2 120 kV lines.	MI		Other	Not Shared	$3,500,000	12/31/2007	120		A
A	East	ITC	907	Goodison Station	Build Goodison Station, with a Belle River-Goodison 345 kV, Pontiac-Goodison 345 kV, new 345/120 kV Xfmr, new Pontiac-Goodison 120 kV line, Goodison-Tienken 120 kV, Sunbird-Goodison 120 kV, and Tienken-Spokane 120 kV.	MI		BaseRel	Shared	$50,000,000	12/31/2009	345	120	A

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A	East	ITC	910	Coventry Station upgrade	Constructs new Coventry-Cody 230 kV line using the same right-of-way currently occupied by the Coventry-Cody 120 kV circuit. Project involves constructing a new 345/230 kV tranformer at Coventry along with a 230/120 kV transformer at Cody. Project also invloves expansion of the Coventry 345 kV station.	MI		BaseRel	Shared	$25,600,000	12/31/2007	345	120	A
A	East	ITC	911	Placid 345/120 transformer #2	Construct second 345/120 kV transformer at the Placid station. Project involves expansions at both Placid 120 kV and 345 kV stations	MI		BaseRel	Shared	$5,550,000	12/31/2007	345	120	A
A	East	ITC	1011	Durant-Genoa 120 kV	Builds a new 120 kV Durant sub-station with a new circuit from Genoa to Durant	MI		Other	Not Shared	$15,000,000	12/31/2007	120		A
A	East	ITC	1301	Yost Line Breaker	Adds a line breaker on the Yost end of the Yost-Polaris 120 kV Circuit to reduce the trasnmission system exposure to faults on distribution circuits	MI		Other	Not Shared	$300,000	12/31/2008	120		A
A	East	ITC	1302	Hines and Walton Station Equipment Replacement	Replaces equipment and buses at Hines and Walton Stations to increase thermal ratings to relieve overloads	MI		Other	Not Shared	$750,000	12/31/2007	120		A
A	East	ITC	1309	Breaker Replacement Program	Targets the replacement of breakers nearing their end of life where maintenance costs will be just as high as new breakers	MI		Other	Not Shared	$3,000,000	12/31/2007	345		A
A	East	ITC	1310	Breaker Replacement Program	Targets the replacement of breakers nearing their end of life where maintenance costs will be just as high as new breakers	MI		Other	Not Shared	$2,000,000	12/31/2007	230		A
A	East	ITC	1488	Break up 3-ended Prizm-Proud-Placid 120 kV line	Results in Placid to Durant and Placid to Proud (Durant substation replaces Prizm sub).	MI		Other	Not Shared	$4,000,000	6/1/2008	120		A
A	West	MDU	548	Bismarck Downtown-East Bismarck 115 kV upgrade to at least 160 MVA	Bismarck Downtown-East Bismarck 115 kV upgrade to at least 160 MVA	ND		BaseRel	Not Shared	$363,000	11/1/2007	115		A
A	West	MDU	1008	Bismarck/Mandan 115 kV Circuits transferred from old to new Memorial Bridge	Bismarck/Mandan 115 kV Circuits transferred from old to new Memorial Bridge	ND		Other	Not Shared	$6,560,000	11/1/2009	115		A
A	East	METC	481	Tallmadge 345/138 kV TB3 transformer #3	Tallmadge 345/138 kV TB3 transformer #3 addition	MI		BaseRel	Shared	$9,913,090	12/1/2008	345	138	A
A	East	METC	497	Tallmadge - Wealthy Street 138 kV line #2	Tallmadge - Wealthy Street 138 kV line #2	MI		Other	Excluded	$40,000	6/1/2007	138		A
A	East	METC	658	Gaylord - Livingston 138 ckt # 1	Reconductor 1.5 miles to 795 ACSS	MI		TDSP	Not Shared	$500,000	5/1/2008	138		A
A	East	METC	660	Keystone - Clearwater - Stover 138 kV line Phase 1	Keystone to Clearwater 138 kV line - rebuild 23.2 miles to 795 ACSS	MI		BaseRel	Shared	$10,200,000	5/1/2009	138		A
A	East	METC	740	345 kV line relaying and communications upgrade project - Phase 1	Phase 1 Upgrade 345 kV line relaying and communications on Gallagher - Tittabawassee, Keystone - Livingston, and Livingston - Gallagher lines.	MI		Other	Excluded	$2,794,000	3/1/2009	345		A
A	East	METC	981	Wabasis	Install a tap pole and two switches on N. Belding - Vergennes 138kV Line	MI		Other	Not Shared	$160,000	6/1/2009	138		A
A	East	METC	988	Simpson - Batavia 138 kV line	Simpson - Batavia 138 kV line - Build 30 miles new 138 kV line, 795 ACSS	MI		BaseRel	Shared	$13,000,000	12/31/2009	138		A
A	East	METC	1015	Oden	Oden - New Capacitor	MI		BaseRel	Not Shared	$510,000	6/1/2008	138		A
A	East	METC	1016	Bard Road	Bard Road - New Capacitor	MI		BaseRel	Not Shared	$596,000	6/1/2008	138		A
A	East	METC	1017	Croton	Croton - New Capacitor	MI		BaseRel	Not Shared	$596,000	6/1/2008	138		A

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A	East	METC	1390	Goss Station 345kV Bus	Rebuild Goss 345kV bus from GIS to air insulated and replace 345kV breakers	MI		Other	Not Shared	$5,800,000	12/1/2007	345		A
A	East	METC	1391	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 148 at Campbell	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1392	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 188 at Campbell	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1393	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 288 at Campbell	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1394	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 388 at Campbell	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1395	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 500 at Campbell	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1396	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 588 at Campbell	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1397	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 36M9 at Spaulding	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1398	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 36B7 at Spaulding	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1399	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 377 at Morrow	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1400	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 288 at Claremont	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1401	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 388 at Claremont	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1402	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 13B7 at Goss	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1403	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 13M9 at Goss	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1404	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 6W8 at Argenta	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1405	Overdutied Breaker Replacement Plan -Year 5 of 5	Replace 138kV breaker 499 at Hemphill	MI		Other	Not Shared	$160,000	12/31/2007	138		A
A	East	METC	1406	Breaker Repair or Replace Program	Replace 138kV Alpena 188 breaker	MI		Other	Not Shared	$160,000	12/31/2008	138		A
A	East	METC	1407	Ludington 345kV Reactor	Repair or replace faulty (gasing) 100MVAR reactor and replace the existing circuit switcher with a breaker	MI		Other	Not Shared	$1,500,000	12/1/2007	345		A
A	East	METC	1408	RTU / SCADA upgrade	Install and/or upgrade RTU's and SCADA points throughout system	MI		Other	Not Shared	$801,000	5/1/2007	345	138	A
A	East	METC	1410	Mobile 138kV Bulk Capacitor	Purchase a mobile 14.4 - 36MVAR capacitor for flexible use where needed throughout the system	MI		Other	Not Shared	$700,000	12/1/2008	138		A
A	East	METC	1412	Covert - Negative Sequence Mitigation	Re-arrange phases on 345kV Palisades-Argenta Ckt #1 or #2 and on 345kV Palisades-Cook Ckt #2	MI		BaseRel	Not Shared	$735,000	11/1/2007	345		A
A	East	METC	1413	Bagley-Gaylord 138kV line	Rebuild line to 795 ACSS	MI		BaseRel	Not Shared	$350,000	5/1/2009	138		A
A	East	METC	1414	Thetford 345kV Line Relaying	Upgrade line relaying on 345kV lines	MI		Other	Not Shared	$300,000	12/31/2007	345		A

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A	East	METC	1415	Solar	Install a tap pole and one switch on each of the Tittabawassee-HSC and Lawndale-HSC 138kV lines.	MI		Other	Not Shared	$160,000	10/1/2007	138		A
A	East	METC	1416	Tittabawassee-Hemlock Semiconductor 138 kV line	Install a second 138kV Tittabawasee-HSC line (14.7 miles) along with required 138kV breakers at each end (5 total breakers) and install a 2 mile 138kV double circuit to swap the existing Tittabawasee and Lawndale line connections into HSC.	MI		BaseRel	Shared	$7,227,000	10/1/2007	138		A
A	East	METC	1419	Laundra	Install a tap pole and one switch on Bullock-Saginaw River 138kV Line	MI		Other	Not Shared	$80,000	7/31/2007	138		A
A	East	METC	1420	Sanderson	Install a tap pole and one switch on North Belding-Sanderson 138kV Line	MI		Other	Not Shared	$80,000	11/1/2007	138		A
A	East	METC	1421	Baraga (formerly Sinclair or Spectrum)	Install a 138kV tie-breaker to loop the Spaulding-Four Mile 138 kV Line into Baraga.	MI		Other	Not Shared	$240,000	12/15/2007	138		A
A	East	METC	1422	Marshall	Install a tap pole and one switch on the Verona-Marshall 138kV line.	MI		Other	Not Shared	$80,000	6/1/2007	138		A
A	East	METC	1423	Eppler	Install a tap pole and two switches on the Emmet-McNally 138kV line. Purchase the high side of Emmet Substation and a section of the 138kV line from the substation to the Eppler tap point.	MI		Other	Not Shared	$500,000	6/1/2007	138		A
A	East	METC	1425	Gray Road	Install a tap pole and two switches on Keystone-Elmwood 138kV Line plus some relay upgrades	MI		Other	Not Shared	$300,000	6/1/2008	138		A
A	East	METC	1433	Buskirk	Install bulk substation served from the Beals-Hazelwood 138kV Line	MI		Other	Not Shared	$2,200,000	6/1/2008	138		A
A	East	METC	1434	Five Mile	Install bulk substation served from the Spaulding 138kV ring bus	MI		Other	Not Shared	$750,000	6/1/2008	138		A
A	East	METC	1437	N Ave	Install a tap pole and two switches on Argenta-Milham 138kV Line	MI		Other	Not Shared	$160,000	6/1/2008	138		A
A	East	METC	1438	Potvin	Install a tap pole and one switch on Wexford-Tippy 138kV Line	MI		Other	Not Shared	$80,000	6/1/2008	138		A
A	East	METC	1439	Busch	Install a tap pole and two switches on Hemphill-Weadock 138kV Line	MI		Other	Not Shared	$160,000	10/1/2007	138		A
A	East	METC	1440	Huckleberry	Install a tap pole and two switches on Beals Rd-Wayland-Hazelwood 138kV Line	MI		Other	Not Shared	$80,000	6/1/2008	138		A
A	East	METC	1441	Ellis (Hile Road)	Install bulk substation served from a new Ellis spur from Sternberg	MI		Other	Not Shared	$3,250,000	6/1/2009	138		A
A	East	METC	1442	Eastmanville (Pingree)	Install bulk substation served from the Fillmore-Four Mile 138kV Line	MI		Other	Not Shared	$200,000	10/1/2007	138		A
A	East	METC	1444	Dublin	Install a tap pole and two switches on Bullock-Edenville 138kV Line	MI		Other	Not Shared	$160,000	6/1/2011	138		A
A	East	METC	1445	Emmet	Install a second distribution transformer at Emmet	MI		Other	Not Shared	$2,750,000	6/1/2010	138		A
A	East	METC	1446	Gaines	Install bulk substation at Gaines	MI		Other	Not Shared	$50,000	6/1/2010	138		A
A	East	METC	1447	Horseshoe Creek (Deja)	Install bulk substation served from the Eureka-Deja-Vestaburg 138kV Line	MI		Other	Not Shared	$2,200,000	6/1/2010	138		A

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A	East	METC	1449	Juniper	Install bulk substation served from the Cobb-Tallmadge #2 138kV Line	MI		Other	Not Shared	$160,000	6/1/2010	138		A
A	East	METC	1465	G418, 38068-02	Construction Suspended on 5/15/2006, can be suspended for 3 years. Net:	MI		GIP	Shared	$5,192,616	10/1/2007	138	69	A
B>A	West	MP	277	Badoura Project: Pine River - Pequot Lakes 115 kV line	Pine River - Pequot Lakes 115 ckt 1, Sum rate 182	MN		BaseRel	Shared	$13,896,026	5/1/2010	115		A
C>A	West	MP	1025	G519 - Mesaba	Network Upgrades associated with 600 MW coal gasification generating facility at the propsoed Mesaba generating station.	MN		GIP	Shared	$76,319,541	7/1/2012	230	115	A
B>A	West	MP	1286	'Add a 25 Mvar capacitor bank & Switching station at Two Harbors	'Add a 25 Mvar capacitor bank & Switching station at Two Harbors	MN		BaseRel	Not Shared	$1,750,000	6/1/2008	115		A
B>A	West	MP	1359	International Falls - Capacitor 115 add new	International Falls - Capacitor 115 add new	MN		BaseRel	Not Shared	$245,000	6/30/2007	115		A
C>A	West	MP/GRE	1021	Embarass to Tower 115 kV Line	115 kV line from 34L tap to Tower 46 kV	MN		Other	Not Shared	$7,314,000	11/1/2009	115		A
B>A	West	MP/GRE	1022	Badoura-Long Lake 115 kV line	115 kV line from MP Badoura to GRE Long Lake	MN		BaseRel	Shared	$8,621,000	5/1/2009	115		A
C>A	West	MP/GRE	1361	Badoura - Birch Lake 115 lines	Badoura - Birch Lake 115 lines	MN		Other	Not Shared	$9,330,545.00	12/31/2009	115		A
A	West	MPC/XEL/OTP	279	Bemidji-Grand Rapids 230 kV Line	Boswell - Wilton 230 ckt 1, Sum rate 495	MN		BaseRel	Shared	$72,360,000	7/1/2010	230		A
B>A	East	NIPS	612	Hiple - Add 2nd 345-138 kV Transformer	Install a 2nd 345/138 kV 560 MVA transformer, associated breakers and bus at F.G. Hiple Substation.	IN		BaseRel	Shared	$5,799,614	5/1/2008	345	138	A
A	East	NIPS	757	Dune Acres - Add 138 kV Capacitors - 100 MVAR	Add one step of capacitors, for a total 100 MVAR, on the Dune Acres 138 kV bus.	IN		Other	Excluded	$1,083,600	12/1/2007	138		A
A	East	NIPS	925	ISG2 to Marktown - Upgrade Capacity	Upgrade circuit capacity on existing .6 miles of 300 KCM Cu line by bundling both sets of 300 KCM CU line on shared tower line between Marktown and ISG #2 to increase capacity to 316 MVA.	IN		BaseRel	Not Shared	$240,500	8/1/2007	138		A
A	East	NIPS	1298	Inland #5 to Marktown - Upgrade Capacity	Upgrade Cir. 13830 capacity on existing 2.2 miles of 400 KCM Cu line by upgrading conductor to 954 KCM ACSR between Marktown and Inland #5 Substation.	IN		BaseRel	Not Shared	$750,000	5/1/2008	138		A
C>A	East	NIPS	1615	G439 - Benton County Wind	Network Upgrades associated with 100 MW wind farm in Benton County IN	IN		GIP	Shared	$2,640,000.00	10/31/2007	138		A
A	West	OTP	274	Appleton - Dawson 115 kV Line	Appleton - Dawson 115 kV line, conversion of 41.6 kV line to 115 kV	MN		Other	Not Shared	$2,080,600	8/1/2008	115	12.5	A
A	West	OTP	275	Canby - Dawson 115 kV Line	Dawson - Canby 115 ckt 1, Sum rate 96	MN		Other	Not Shared	$519,400	8/1/2008	115		A
A	West	OTP / GRE	1462	G380, 37946-02	Net: Transmission Owner will upgrade the Rugby Substation to accomdate the interconnection of the IC's 230 kV radial transmission line into Rugby, will need to add additional 230 kV bus, new 230 kV breaker and associated equipment.	ND		GIP	Shared	$898,740	9/1/2007	230		A
A	West	OTP/MRES/GF	755	Alexandria Capacitor Addition	Alexandria Switching Station 115 kV 25 MVAR Capacitors	MN		BaseRel	Not Shared	$530,000	6/1/2008	115		A
A	Central	SIPC	81	Marion Power Plant - Carrier Mills 161 kV line	Construct a 161 kV line connecting the Marion 161 kV Plant to a new Carrier Mills 161/69 kV Substation. The project includes the construction of nearly 27 miles of 161 kV transmission line and converting a 69 kV switching station into a 161/69 kV substation.	IL		Other	Excluded	$7,083,000	6/1/2007	161		A
A	Central	Vectren (SIGE)	1004	New 345/138 kV Substation at Francisco	Francisco 345/138 kV substation with one 448 MVA transformer	IN		BaseRel	Shared	$16,000,000	7/9/2007	345	138	A

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A	Central	Vectren (SIGE)	1257	New transmission line Gibson (Cinergy) to AB Brown to Reid (BREC)	New 345 kV transmission line Gibson (Cinergy) to AB Brown to Reid (BREC)	IN	KY	BaseRel	Shared	$66,000,000	5/31/2011	345		A
A	Central	Vectren (SIGE)	1259	New transmission line Dubois to Newtonville	New transmission line Dubois to Newtonville	IN		BaseRel	Shared	$14,400,000	7/1/2007	138		A
A	East	WPSC	1208	Oden 12MVAR Capacitor Bank	Add 12MVAR Capacitor Bank at Oden Substation	MI		Other	Not Shared	$300,000	12/31/2007	69		A
A	East	WPSC	1226	Kalkaska Gen - Westwood Line Rebuild	Kalkaska Gen - Kalkaska JCT - Westwood Line Rebuild. Summer Rating 102.4 MVA	MI		Other	Not Shared	$2,905,000	2/1/2008	69		A
A	East	WPSC	1227	Gaylord Gen - Bagley Junction	Gaylord Gen - Bagley Junction Rebuild. Summer Rating 102.4 MVA	MI		Other	Not Shared	$1,000,000	2/1/2008	69		A
A	East	WPSC	1228	ANR Elpaso New Load	Add 14MW load off of Wolverine's Westwood Junction	MI		Other	Not Shared	$1,800,000	8/1/2008	69		A
A	East	WPSC	1229	Plains Junction Breaker Station	Replace Relaying and Breakers at Plains Junction Substation	MI		Other	Not Shared	$625,000	12/31/2007	69		A
A	East	WPSC	1230	White Cloud Breaker Station	Replace Relaying and Breakers at White Cloud Substation	MI		Other	Not Shared	$625,000	7/31/2007	69		A
A	East	WPSC	1272	Redwood 75MVA Transformer	Add 75MVA Transformer at Redwood Substation a separate line from Redwood Junction will be ran to energize the transformer.	MI		Other	Not Shared	$1,900,000	8/1/2010	138	69	A
A	West	XEL	56	Chisago - Apple River	Chisago - Lindstrom - Shafer- Lawrence Creek 69 kV rebuild to 115 kV, Lawrence Creek - St Croix Falls - Apple River 69 kV rebuild to 161 kV. New Lawrence Creek 161/115/69 kV substation	MN		Other	Excluded	$36,111,000	12/31/2010	161	69	A
A	West	XEL	270	Champlin - Champlin Tap 115	Champlin - Champlin Tap 115 ckt 1, Sum rate 310	MN		Other	Excluded	$382,923	6/1/2008	115		A
A	West	XEL	385	Xcel Energy Wind 425-825 MW project	Buffalo Ridge (SW MN) 825 MW of Generation Outlet:Split Roc	MN		TDSP	Not Shared	$124,947,481	1/1/2010	345	115	A
A	West	XEL	609	Long Lake - Oakdale 115 kV line	Long Lake - Oakdale 115 kV line	MN		Other	Excluded	$760,000	12/31/2007	115		A
A	West	XEL	673	Champlin Tap - Crooked Lake 115	Champlin Tap - Crooked Lake 115 ckt # 1	MN		BaseRel	Not Shared	$310,000	7/1/2008	115		A
A	West	XEL	674	High Bridge - Rogers Lake 115	High Bridge - Rogers Lake 115 ckt # 1	MN		TDSP	Not Shared	$2,400,000	6/1/2008	115		A
A	West	XEL	778	Nobles Co 34.5 kV 50 Mvar Reactor #2	Nobles Co 34.5 kV 50 Mvar Reactor #2	MN		TDSP	Direct Assigned	$200,000	11/1/2007	34.5		A
A	West	XEL	780	Lakefield Gen - Wilmarth Series Compensation	Fieldon Township 345 kV Series Capacitor 20 ohms	MN		TDSP	Not Shared	$10,100,000	11/1/2007	345		A
A	West	XEL	1031	Garwind McNeilus generator TSR upgrades	TSR conditional upgrades for delivery of G171, G239, G242	MN		TDSP	Not Shared	$780,000	3/1/2008	69		A
A	West	XEL	1364	Lakefield Jct - Lakefield Generation 345 kV line - Raise the structures to increase the thermal rating	Lakefield Jct - Lakefield Generation 345 kV line - Raise the structures to increase the thermal rating	MN		TDSP	Not Shared		1/30/2007	345		A
A	West	XEL	1365	Edina - Eden Prairie 115 Reconductor	Edina - Eden Prairie 1 115 Reconductor	MN		BaseRel	Not Shared	$3,730,000	12/31/2007	115		A
A	West	XEL	1366	G405: Colvill Generating station - Interconnection upgrades	Colvill Generating station - Transformer relocated from Cannon Falls substation, Build in and out to Cannon Falls - Empire 115 kV line, Build in and out to Cannon Falls - Spring Creek 161 kV line	MN		GIP	Shared	$13,943,380	5/1/2008	161	115	A
A	West	XEL	1454	G176, 37319-01	Net: Yankee Substation 115/34.5 kV transformer Int: two 34.5 feeder bays at Yankee Sub terminating at the dead-end switch structures outside Yankee Sub.	MN		Other	Not Shared (Pre-RECB 1)	$2,306,000	9/1/2007	115	34.5	A

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A	West	XEL	1455	G238, 37642-02, Increase of generating capacity at Riverside Generating Plant	Net: 3 new 115 kV, 63 kA interrupting rating circuit breakers, disconnect switches, and relocate the existing Apache 115 kV line to a new termination in the same substation	MN		Other	Not Shared (Pre-RECB 1)	$2,770,000	5/1/2009	115		A
A	West	XEL	1456	G255, 37517-01	Net: a new 120 MVA, 118-36.2 kV transformer, 2 115 kV breakers, 115 kV switches and 34.5 kV breakers and switches. Int: install two new 50 MW feeders and all associated equipment.	MN		GIP	Shared	$3,357,600	11/1/2007	115		A
A	West	XEL	1457	G287, 37642-03. Upgrades for G287	G287 Upgrades: Nobles County sub upgrades, Hazel Creek substation, Nobles County - Fenton 115 kV line, Hazel Creek capacitor and SVC	MN		GIP	Shared	$38,735,000	12/31/2010	345		A
A	West	XEL	1458	G349, 37774-01. Upgrades for G349	G349 Upgrades: Yankee substation, Brookings Co 345/115 substation, Hazel Run 53 Mvar capacitor, Brookings-Yankee 115 kV line	MN		GIP	Shared	$31,982,000	11/30/2011	345	115	A
A	West	XEL	1489	Woodbury - Tanners Lake upgrade	Reconductor the line from Woodbury - Tanners Lake to 310 MVA	MN		BaseRel	Not Shared	$525,000	6/1/2009	115		A
C>A	West	XEL	1613	G386 - Trimont Wind	Network Upgrades for Project G386, a 100 MW (gross Summer output rating) wind Generating Facility interconnecting at the 345kV Trimont Wind Substation in Martin County, Minnesota. The Trimont Wind Substation and the 345kV line were designed to accommodate three wind generation projects of approximately 100 MW each, Projects G263 and G386 being the first two.	MN		GIP	Shared	$4,779,000	5/30/2012	115		A
C>A	West	XEL	1614	G426	G426 Network Upgrades for a 100 MW wind farm to be located in Osceola and Dickinson County, Iowa (ALTW system)	MN		GIP	Shared	$4,803,000	5/30/2012	115		A
A	Central	DEM	853	West Lafayette to Cumberland 138 Reconductor	Reconductor section of 13806 circuit with 954ACSR 100C.	IN		Other	Not Shared	$706,921	6/1/2015	138		A
A	West	ALTW	1344	Build a new 345 kV Beverly substation which taps the Arnold - Tiffin 345 kV line	Build a new 345 kV Beverly Tap substation and tapped to 345 kV line Arnold -Tiffin at 40% distance away from Arnold. Add a new 335 MVA 345/161 kV transformer and build a new 161 kV line connecting the new substation to Beverly 161 kV bus	IA		Other	Not Shared	$4,300,000	6/1/2016	345	161	A

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App ABC	Region	Reporting Source	PrjID	Facil ID	Expected ISD	From Sub	To Sub or Equipment	Ckt	High kV	Low kV	Ratings	Upgrade Description	State	Miles Upg	Miles New	Planning Status	Estimated Cost	C.S.	P.S.	M07 ABC
A		**Appendix A**																		A
A	West	ALTW	90	189	6/1/2007	Emery	Lime Creek	2	161		326	New Facility	IA		25.0	Under Constr	$8,000,000			A
A	West	ALTW	1287	2116	6/1/2008	Salem 345/161 kV	transformer	1	345	161	448/448	Larger Xfmr	IA			Planned	$5,000,000	Y		A
A	West	ALTW	1288	2117	6/1/2009	Hazleton 345/161	transformer	1	345	161	335/335	Larger Xfmr	IA			Planned	$5,000,000	Y		A
A	West	ALTW	1289	2118	6/1/2008	Marshalltown	Toledo	1	115		233/233	Rebuild	IA	16.0		Planned	$4,712,000			A
A	West	ALTW	1289	2119	6/1/2009	Belle Plaine	Toledo	1	115		233/233	Rebuild	IA	18.0		Planned	$6,080,000			A
A	West	ALTW	1289	2120	6/1/2010	Belle Plaine	Stoney Point	1	115		233/233	Rebuild	IA	27.0		Planned	$8,208,000			A
A	West	ALTW	1342	2208	6/1/2011	Lewis Fields	Hiawatha	1	161		250	new line	IA		8.5	Planned	$2,550,000			A
A	West	ALTW	1342	2209	6/1/2011	Lewis Fields	transformer	1	161	115		new transformer	IA			Planned	$2,000,000			A
A	West	ALTW	1471	2473	5/1/2007	Miloma - Round Lake 69 kV		1	69			transmission structure with a 3-way, load break, manual, 1200 amp or higher, 69 kV switch	MN			Planned	$125,000	Y		A
A	West	ALTW	1472	2475	5/1/2007	West Lakefield Tap 69 kV bus		1	69			transmission structure with a 3-way, load break, manual, 1200 amp or higher, 69 kV switch	MN			Planned	$125,000	Y		A
A	West	ALTW	1473	1856	6/1/2008	Mason City Armor	Emery North	1	69			Rebuild existing line	IA			Proposed				A
B>A	West	ALTW	1541	2618	4/25/2007	Panora	capacitors		34.5		2.4 MVAR	install 2.4 MVAR cap bank; Panora distribution sub	MN			Planned	$260,000	Y		A
A	Central	Ameren	78	59	6/1/2008	Loose Creek	Jefferson City	1	345		1606	new 345 kV line	MO		15.0	Planned	$10,180,500			A
A	Central	Ameren	78	65	6/1/2008	Jefferson City 345/161	transformer	1	345	161	450	new 345/161 kV transformer	MO			Planned	$7,440,000			A
A	Central	Ameren	144	392	6/1/2008	Crab Orchard	Marion South	1	138		269	reconductor	IL	9.1		Planned	$1,557,100			A
A	Central	Ameren	149	397	6/1/2007	Mason	Sioux	1	345			breaker addition at Mason	MO			Planned	$799,000			A
A	Central	Ameren	150	398	6/1/2008	Rush Island	Baldwin	1	345		1793	terminal at Rush Island & river crossing only	IL		2.0	Planned	$1,615,100			A
C>A	Central	Ameren	152	399	12/1/2010	Big River	Rockwood	1	138		370	new line	MO		10.0	Proposed	$13,381,100	Y		A
A	Central	Ameren	153	400	6/1/2008	CEE Tap	Watson	1	138		370	reconductor	MO	0.8		Planned	$277,200			A
A	Central	Ameren	155	401	6/1/2008	Joachim 345/138 kV	transformer	1	345	138	560	new 345/138 kV transformer	MO			Planned	$13,345,100			A
A	Central	Ameren	708	1399	6/1/2007	Casey	Breed	1	345		1332	reconductor river crossing	IL	0.2		Planned	$457,600			A
A	Central	Ameren	712	1403	12/1/2007	Mason	Labadie-Mason-4 Term. Equipment replacement	1	345			terminal equipment upgrade at Mason	MO			Planned	$312,900			A
A	Central	Ameren	715	1406	6/1/2008	Wildwood	Gray Summit	1	138		415	reconductor	MO	0.1		Proposed	$132,700			A
A	Central	Ameren	716	1407	6/1/2008	Wildwood	Gray Summit	2	138		415	reconductor	MO	0.1		Proposed	$132,700			A
A	Central	Ameren	719	1410	6/1/2009	Labadie Plant	Replace 4-345 kV Breakers		345			replace existing 345 kV breakers	MO			Planned	$2,511,700			A
C>A	Central	Ameren	783	3094	6/1/2007	Robinson-Marathon	Cap. - Increase 18 Mvar to 36 Mvar		138		36 Mvar	increase size of existing 138 kV capacitor	IL			Planned	$259,200			A
A	Central	Ameren	857	832	6/1/2008	Rush Island	Joachim	1	345		1200	Replace terminal equipment at Rush Island	MO			Planned	$285,400			A
A	Central	Ameren	858	833	6/1/2007	Sioux	Huster	1	138		214	Increase ground clearance	MO	6.0		Planned	$520,100			A
A	Central	Ameren	859	834	6/1/2008	Central	Watson (Tower 55)	1	138		370	Reconductor 5.1 miles 954 kcmil ACSR from Central to Twr. 55	MO	5.1		Planned	$2,681,600			A
A	Central	Ameren	1241	1942	3/1/2008	Mattoon, West	Install 138 kV Breaker at Mattoon, West	1	138			Install 138 kV Breaker to connect Wind Farm	IL			Planned	$659,400			A
A	Central	AmerenCILCO	141	386	12/1/2007	Duck Creek	Tazewell	1	345			convert bus duct to OH	IL			Planned	$119,500			A
A	Central	AmerenCILCO	876	854	6/1/2007	Tazewell	Powerton	1	345		1339	Replace 2000 A terminal equipment at Tazewell with 3000 A	IL			Planned	$1,203,300			A
A	Central	AmerenIP	150	1422	6/1/2008	Baldwin	Rush Island	1	345		1793	26 miles of new 345 kV line	IL		26.0	Planned	$46,149,200			A
A	Central	AmerenIP	150	1423	6/1/2008	Line 4531 tap	Prairie State Power Plant	2	345		1470	345 kV connection to new generation	IL		7.5	Planned	$12,178,600			A
A	Central	AmerenIP	150	1424	6/1/2008	Line 4541 tap	Prairie State Power Plant	2	345		1470	345 kV connection to new generation	IL		1.5	Planned	$2,172,100			A
A	Central	AmerenIP	150	1667	6/1/2008	Prairie State	substation	1	345		1793	new switchyard (6 position, 4 lines, 2 units)	IL			Planned	$15,872,700			A
A	Central	AmerenIP	725	1418	12/1/2008	N. LaSalle	Wedron Fox River	1	138		266	2 CB at N LaSalle, 1 CB at Wedron Fox River Substation	IL		25.0	Planned	$21,357,530			A
A	Central	AmerenIP	726	1419	12/1/2008	Ottawa	Wedron Fox River	1	138		266	1 CB at Ottawa, new 138 kV line to Wedron Fox River Substation	IL		8.0	Planned	$8,962,967			A
A	Central	AmerenIP	728	1421	6/1/2008	Wood River	Roxford L1502	1	138		382	reconductor	IL	4.4		Planned	$4,605,700	Y		A
A	Central	AmerenIP	732	1425	12/1/2007	S. Bloomington	State Farm	1	138		337	Reconductor 1.3 miles 1272 kcmil ACSR	IL	1.3		Under Constr	$1,085,900			A
A	Central	AmerenIP	736	1429	12/31/2007	W. Tilton	Tilton Energy Center		138			new 138 kV breaker addition at W. Tilton	IL			Under Constr	$2,658,600			A
A	Central	AmerenIP	738	1431	12/15/2007	Line 1342C tap	Line 1342A	1	138		280	Line 1342A (structure 423 to 467A reconductor)	IL	5.2		Under Constr	$2,035,000			A

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A	Central	AmerenIP	739	1432	1/1/2009	Line 4561 Tap	Franklin County Power Plant	1	345			345 kV connection (new ring bus) to new generation	IL			Proposed	$6,410,900			A
A	Central	AmerenIP	865	841	6/1/2009	Havana	Monmouth	1	138		280	Build new river crossing	IL		0.4	Planned	$2,674,600			A
C>A	Central	AmerenIP	866	842	6/1/2007	Latham 345/138 kV Substation	Mason City-Decatur Line 1342	1	138		160	Install 138 kV breaker for 'in-out' taps to Line 1342, construct 0.38 mile 138 kV line	IL		0.4	Proposed	$1,494,400			A
A	Central	AmerenIP	869	845	9/1/2007	Sidney	Mira Tap	1	138		280	Reconductor 2 miles of 795 kcmil ACSR	IL	2.0		Under Constr	$634,300			A
C>A	Central	AmerenIP	870	846	6/1/2008	Sidney	Paxton	1	138		399	Reconductor 18 miles of 350 kcmil Cu	IL	18.0		Proposed	$5,878,500	Y		A
A	Central	AmerenIP	873	849	1/31/2009	Baldwin	W. Mt. Vernon	1	345		1195	Replace 345 kV breakers at Baldwin terminal	IL			Planned	$4,077,600			A
A	Central	AmerenIP	873	850	1/31/2009	Baldwin	Stallings	1	345		1195	Replace 345 kV breakers at Baldwin terminal	IL			Planned	$4,077,600			A
A	Central	AmerenIP	873	851	1/31/2009	Baldwin	Turkey Hill	1	345		1195	Replace 345 kV breakers at Baldwin terminal	IL			Planned	$4,077,600			A
C>A	Central	AMIL	1615	2666	10/31/2007	Watseka Substation			138			System Protection Relay Changes at Watseka Substation - G439 FCA	IL			Planned	$380,000	Y		A
A	West	ATC LLC	1	855	6/1/2008	Stone Lake	Inductor		345		75 Mvar		WI			Planned	$0			A
A	West	ATC LLC	1	2064	6/1/2008	Arpin	Capacitor bank		138		50 Mvar		WI			Planned	$1,021,496			A
A	West	ATC LLC	1	3099	6/1/2008	Stone Lake	Capacitor		345		75 Mvar		WI			Planned	$0			A
A	West	ATC LLC	1	135	6/30/2008	Arrowhead	Stone Lake	1	345		1092/1092 MVA	new line	MN/WI		78.9	Under Constr	$130,497,677			A
A	West	ATC LLC	101	125	6/1/2008	Kelly	Whitcomb		115		121/165 MVA	uprate clearances to 300F	WI	24.3		Planned	$1,900,000			A
A	West	ATC LLC	175	463	11/1/2007	Ellinwood	Sunset Point		138		289 MVA SE		WI	3.6		Planned	$2,500,000			A
A	West	ATC LLC	177	2456	5/1/2008	Caroline	Belle Plaine	1	115		290/401 MVA		WI			Under Constr	$0			A
A	West	ATC LLC	177	2455	3/1/2009	Whitcomb	Caroline	1	115		239/239 MVA		WI			Planned	$0			A
A	West	ATC LLC	177	2457	6/1/2009	Belle Plaine	Badger	1	115		175/240 MVA		WI			Under Constr	$0			A
A	West	ATC LLC	177	607	12/1/2009	Gardner Park (new Weston)	HWY 22 (formerly Central Wisconsin)	1	345		1776 MVA SE		WI		47.0	Planned	$116,700,000			A
A	West	ATC LLC	177	862	12/1/2009	HWY 22 (formerly Central Wisconsin)	new substation		345			new substation	WI			Planned	$12,200,000			A
A	West	ATC LLC	177	2454	12/1/2009	Kelly	Whitcomb	1	115		174/174 MVA		WI			Planned	$0			A
A	West	ATC LLC	339	429	5/31/2009	Lakehead Cambridge	Jefferson		138		348	uprate	WI			Planned	$150,000			A
A	West	ATC LLC	339	433	5/31/2009	Rockdale	Lakehead Cambridge		138		287	uprate	WI			Planned	$200,000			A
A	West	ATC LLC	339	434	5/31/2009	Rockdale	Boxelder	1	138		383	uprate	WI			Planned	$200,000			A
A	West	ATC LLC	339	449	5/31/2009	Jefferson	Lake Mills (provisional)		138		290	construct new	WI		6.0	Planned	$9,850,000			A
A	West	ATC LLC	339	450	5/31/2009	Lake Mills (provisional)	Stonybrook		138		290	construct new	WI		6.0	Planned	$9,850,000			A
A	West	ATC LLC	339	892	5/31/2009	Boxelder	Stonybrook		138		287	uprate	WI			Planned	$200,000			A
A	West	ATC LLC	345	2459	10/1/2007	Morgan	White Clay	1	138		293/332 MVA		WI			Planned	$3,533,329	Y	Y	A
A	West	ATC LLC	345	608	11/30/2008	Clintonville	Werner West		138		381/529 MVA		WI	14.0	2.0	Planned	$6,091,242	Y	Y	A
A	West	ATC LLC	345	480	12/1/2009	Morgan	Werner West		345		1882 MVA SE	new line	WI		47.0	Planned	$128,132,800	Y	Y	A
A	West	ATC LLC	345	2458	12/1/2009	Badger	Clintonville	1	138		211/238 MVA		WI			Planned	$3,533,329	Y	Y	A
B>A	west	ATC LLC	347	597	6/1/2008	Rubicon	Hustisford	1	138		348	new 138 kV line	WI		5.0	Proposed	$6,600,000			A
B>A	west	ATC LLC	347	598	6/1/2008	Hustisford	Hubbard (convert)	1	138		348	convert from 69 kV	WI	8.0		Proposed	$6,091,000			A
B>A	west	ATC LLC	347	3236	6/1/2008	Hubbard 138/69	transformer	1	138	69	100		WI			Proposed	$1,700,000			A
B>A	west	ATC LLC	347	3237	6/1/2008	Hubbard	substation		138	69		New 138-69 kV substation; cost estimate exclude the transformer cost	WI			Proposed	$3,900,000			A
B>A	west	ATC LLC	347	3238	6/1/2008	Rubicon			138			Rubicon 138 kV substation modification	WI			Proposed	$2,081,000			A
A	West	ATC LLC	352	446	6/1/2008	Eagle River	Lakota Rd (formerly Conover)	1	115		244	new line	WI		14.0	Planned	$10,000,000	Y		A
A	West	ATC LLC	352	447	6/1/2008	Lakota Rd (formerly Conover) 138-115 kV	transformer	1	138	115	150	138/115 transformer	WI			Planned	$17,785,000	Y		A
A	West	ATC LLC	352	445	2/1/2009	Lakota Rd (formerly Conover)	Iron Grove	1	138		290	convert 69 to 138 kV	MI/WI	73.0		Planned	$69,100,000	Y		A
A	West	ATC LLC	352	896	2/1/2009	Iron Grove	Substation relocation		138			Iron River rename/relocation	MI			Planned	$5,900,000	Y		A
A	West	ATC LLC	352	2460	9/1/2009	Iron Grove	Aspen	1	138		400 MVA SE		MI/WI			Planned	$5,850,000	Y		A
A	West	ATC LLC	352	1371	12/31/2009	Aspen	Plains	1	138		400 MVA SE		WI			Planned	$5,850,000	Y		A
A	West	ATC LLC	566	1244	10/15/2007	Plymouth	Forest Junction/Charter Steel	1	138		277		WI		1.3	Planned	$2,500,000			A
A	West	ATC LLC	567	1245	12/1/2007	North Appleton	Lawn Road	1	138		287		WI	15.0		Planned	$300,000			A

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A	West	ATC LLC	567	1246	12/1/2007	Lawn Road	White Clay	1	138		287		WI	15.0		Planned	$300,000			A
A	West	ATC LLC	568	1249	6/1/2012	North Lake Geneva	White River	1	138		237	line to new T-D substation	WI		1.4	Proposed	$1,250,000			A
A	West	ATC LLC	570	1255	6/1/2009	La Prairie RCEC	Bradford RCEC	1	138		381		WI			Planned	$1,610,612			A
A	West	ATC LLC	570	1256	6/1/2009	Bradford RCEC	West Darien	1	138		381		WI			Planned	$3,410,708			A
A	West	ATC LLC	570	1257	6/1/2009	West Darien	Southwest Delavan	1	138		381		WI			Planned	$1,610,612			A
A	West	ATC LLC	570	1258	6/1/2009	Southwest Delavan	North Shore	1	138		381		WI			Planned	$3,410,708			A
A	West	ATC LLC	570	1259	6/1/2009	North Shore	Bristol	1	138		381		WI			Planned	$1,610,612			A
A	West	ATC LLC	570	1260	6/1/2009	Bristol	Elkhorn	1	138		292		WI			Planned	$3,410,708			A
A	West	ATC LLC	571	1992	6/1/2008	North Madison	Huiskamp	1	138		481 MVA SE		WI			Proposed	$8,700,000			A
A	West	ATC LLC	572	1262	6/1/2008	Ingalls/Bay de Doc	Menominee	1	138		345		WI		0.5	Proposed	$1,000,000			A
A	West	ATC LLC	572	1264	6/1/2008	Menominee 138/69	transformer	1	138	69			WI			Proposed	$1,915,000			A
A	West	ATC LLC	572	1263	11/1/2008	West Marinette	Menominee	1	138		345		MI/WI		0.5	Proposed	$1,000,000			A
A	West	ATC LLC	877	482	6/1/2009	Oak Creek 345/138 #2	transformer	2	345	138	500		WI			Planned	$6,600,000			A
A	West	ATC LLC	877	863	6/1/2009	Oak Creek	Ramsey		138		293	reconductor (need 382 MVA for A035)	WI	8.5		Proposed	$200,000			A
A	West	ATC LLC	877	864	6/1/2009	Oak Creek	Allerton		138		242	reconductor	WI	5.4		Proposed	$2,000,000			A
A	West	ATC LLC	877	865	6/1/2009	Oak Creek	Relaying replacements		230			replace relaying	WI			Proposed	$2,500,000			A
A	West	ATC LLC	877	866	6/1/2009	Pleasant Prairie	replace two circuit breakers		345			replace circuit breakers	WI			Proposed	$2,357,175			A
A	West	ATC LLC	877	867	6/1/2009	Oak Creek	Expand 345 kV switchyard to interconnect new generator		345			expand switchyard to interconnect new generator	WI			Proposed	$19,277,005			A
A	West	ATC LLC	877	868	6/1/2009	Ramsey	Norwich		138		288	loop Ramsey5-Harbor into Norwich and Kansas to form Ramsey-Norwich and Harbor-Kansas	WI	3.0		Proposed	$200,000			A
A	West	ATC LLC	877	869	6/1/2009	Harbor	Kansas		138		157	loop Ramsey5-Harbor into Norwich and Kansas to form Ramsey-Norwich and Harbor-Kansas	WI	2.7		Proposed	$200,000			A
A	West	ATC LLC	877	870	6/1/2010	Oak Creek	Expand 345 kV switchyard to interconnect second new generator		345			expand switchyard to interconnect second new generator	WI			Proposed	$10,600,000			A
A	West	ATC LLC	877	871	6/1/2010	Kansas	Ramsey6		138		290	uprate	WI	5.7		Proposed	$500,000			A
A	West	ATC LLC	877	872	6/1/2010	Oak Creek	Root River		138		293	uprate	WI			Proposed	$136,007			A
A	West	ATC LLC	877	873	6/1/2010	Oak Creek	Nicholson		138		332	uprate	WI	6.8		Proposed	$136,007			A
B>A	West	ATC LLC	880	878	6/1/2008	North Appleton	Mason Street	1	138		229	uprate 138 kV line	WI	21.0		Proposed	$1,700,000			A
B>A	West	ATC LLC	880	879	6/1/2008	North Appleton	Lost Dauphin	1	138		288	uprate 138 kV line	WI	12.0		Proposed	$1,600,000			A
B>A	West	ATC LLC	882	882	6/1/2007	Ontonagon	Capacitor bank		138		16.32 Mvar	add 2x8.16 Mvar Capacitors	MI			Proposed	$1,200,000			A
B>A	West	ATC LLC	886	886	6/1/2008	North Lake	Substation relocation		138			Cedar substation rename/relocation	MI			Planned	$7,300,000			A
A	West	ATC LLC	1256	1964	4/1/2010	Paddock	Rockdale	2	345		1430	add a second circuit (new line) between the existing 345 kV substations Paddock and Rockdale.	WI	22.7	7.6	Proposed	$112,800,000			A
A	West	ATC LLC	1256	2461	4/1/2010	Rockdale			345			convert to a modifed breaker and a half configuration, replace 5 overdutied 138 kV breakers and replace existing transformer with 500MVA	WI			Proposed	$12,300,000			A
A	West	ATC LLC	1256	2462	4/1/2010	Christiana			138			replace five overdutied 138 kV breakers	WI			Proposed	$1,100,000			A
A	West	ATC LLC	1256	2463	4/1/2010	Paddock			345			upgrade protection system	WI			Proposed	$300,000			A
B>A	west	ATC LLC	1267	1984	6/1/2010	Verona 138/69	transformer	1	138	69	100		WI			Proposed	$1,700,000			A
B>A	West	ATC LLC	1267	1985	6/1/2010	Verona	Oak Ridge	1	138			line to new T-D substation	WI			Proposed	$17,900,000			A
B>A	west	ATC LLC	1267	3234	6/1/2010	Verona			138	69		Expand from existing 69 kV sub; cost estimate exclude the transformer cost	WI			Proposed	$1,200,000			A
B>A	west	ATC LLC	1267	3235	6/1/2010	Oak Ridge			138			new 138 kV substation	WI			Proposed	$1,300,000			A
B>A	West	ATC LLC	1281	2108	6/1/2008	Portage	Trienda	1	138		293/339		WI	3.4		Proposed	$1,031,249			A
B>A	West	ATC LLC	1283	2366	6/1/2008	Tilden	Freeman	1	138		195/202	Retap CT at Freeman for new ratings of 195 SN/202 SE	WI			Planned	$5,000			A
A	West	ATC LLC	1453	467	6/1/2008	Pleasant Valley	Saukville		138		290	reconductor	WI	12.0		Planned	$4,800,000	Y		A
A	West	ATC LLC	1453	468	6/1/2008	Pleasant Valley	St. Lawrence		138		290	reconductor	WI	7.0		Planned	$4,800,000	Y		A

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A	West	ATC LLC	1461	2509	10/20/2006	Green Lake Sub						a collection bus at a voltage level of 34.5kV, 34.5k\	WI			Planned	$170,146			A
A	West	ATC LLC	1461	2511	10/20/2006	Green Lake Sub	transformer		138	34.5	178 MVA	new two-breaker, 138 kV substation in a configurat	WI			Planned	$2,049,696			A
A	West	ATC LLC	1461	2512	10/20/2006	Green Lake Sub			138			a loop into New Substation, including two (2) steel	WI			Planned	$94,856			A
A	West	ATC LLC	1463	2517	10/20/2006	Mishicot	new substation		138			New Substation between Kewaunee Sub and Shot	WI			Planned	$2,612,000			A
A	West	ATC LLC	1463	2518	10/20/2006	Mishicot			138			This interconnection will include extension of the 1:	WI			Planned	$179,000			A
A	West	ATC LLC	1463	2519	10/20/2006	Mishicot			138			Line Y-51 Loop into New Substation. This intercon	WI			Planned	$231,000			A
A	West	ATC LLC	1463	2520	10/20/2006	Kewaunee	Relaying replacements		138			Kewaunee Substation 138 kV Line Y-51, to Shoto,	WI			Planned	$123,000			A
A	West	ATC LLC	1463	2521	10/20/2006	Shoto	Relaying replacements		138			Shoto Substation 138 kV Line Y-51, to Kewaunee,	WI			Planned	$123,000			A
A	West	ATC LLC	1470	2479	11/1/2006	Generating Facility Sub			69			New two-breaker 69 kV substation in a configuratic	WI			Planned	$1,765,957	Y		A
A	West	ATC LLC	1470	2480	11/2/2006	Y-33 line			69		63	existing line Y-33 will be re-built completely to incre	WI			Planned	$5,268,974	Y		A
A	West	ATC LLC	1470	2481	11/3/2006	Y-33 line	S. Monroe		69			replacing the existing line protection relays and pa	WI			Planned	$193,240	Y		A
A	West	ATC LLC	1470	2482	11/4/2006	Y-33 line	Brodhead		69			replacing the existing line protection relays and pa	WI			Planned	$184,941	Y		A
A	West	ATC LLC	1470	2483	11/5/2006	Generating Facility Sub			69			extension of the 69 kV bus to a disconnect switch,	WI			Planned	$125,620			A
C>A	West	ATC LLC	1616	2712	12/28/2007	Loop 138 kV line X-2 throug the new sub			138			Loop 138 kV line X-2 through the new sub	WI			Planned	$343,000	Y		A
C>A	West	ATC LLC	1617	2714	6/1/2011	New G527 auxiliary transformer position			161			Modify the existing 161 kV ring bus, install one new CB and other equipment	WI			Planned	$1,029,000	Y		A
C>A	West	ATC LLC	1617	2715	6/1/2011	Nelson Dewey	Liberty	1	161		292 MVA	New 161 kV line Nelson Dewey - Liberty (cost estimate for WI section of the line, apprx. 2 miles)	WI, IA			Planned	$4,621,000	Y		A
C>A	West	ATC LLC	1617	2716	6/1/2011	New G527 Generator Position at Nelson Dewey			161			Modify the existing 161 kV ring bus, install one new CB and other equipment	WI			Planned	$970,000	Y		A
C>A	West	ATC LLC	1617	2717	6/1/2011	Nelson dewey			161			Terminal work related to the new 161 kV line, install a new CB and other equipment	WI, IA			Planned	$1,435,000	Y		A
C>A	West	ATC LLC	1617	2718	6/1/2011	Nelson dewey			161			Replace three existing CBs at Nelson Dewey 16 kV sub for stability requirement	WI			Planned	$1,771,000	Y		A
C>A	West	ATC LLC	1617	2719	6/1/2011	Nelson dewey			161			Other terminal work at Delson Dewey including grounding, fencing, foundations, etc.	WI			Planned	$1,248,000	Y		A
C>A	Central	CWLP	1620	2726	1/1/2010	Dallman			138			138 kV Breakers, 138 kV Switches, 69 kV Breaker, 138/69 kV Transformer	IL			Planned	$3,642,200	Y		A
C>A	Central	CWLP	1620	2727	1/1/2010	Dallman	Spaulding		138			Line relocation needed to provide clearance for the	IL			Planned	$1,005,500	Y		A
C>A	Central	CWLP	1620	2728	1/1/2010	Dallman	Eastdale		138			Line relocation needed to provide clearance for the	IL			Planned	$1,390,500	Y		A
C>A	Central	CWLP	1620	2729	1/1/2010	Dallman	Franklin Park		69			Line relocation needed to provide clearance for the	IL			Planned	$968,500	Y		A
C>A	Central	CWLP	1620	2730	1/1/2010	Dallman	Stevenson		69			Line relocation needed to provide clearance for the	IL			Planned	$411,300	Y		A
C>A	Central	CWLP	1620	2731	1/1/2010	Dallman	Culver		69			Line relocation needed to provide clearance for the	IL			Planned	$411,300	Y		A
A	Central	DEM	42	184	6/1/2009	Shawswick	Pleasant Grove	1	138		306	Reconductor	IN	18.3		Planned	$4,719,516			A
A	Central	DEM	42	181	6/1/2010	Airport Road Jct	Seymour	1	138		306	Reconductor	IN	2.2		Planned	$752,906			A
A	Central	DEM	42	183	6/1/2010	Pleasant Grove	Airport Road Jct	1	138		306	Reconductor	IN	9.3		Planned	$3,388,077			A
A	Central	DEM	91	2536	12/31/2007	Eastwood	Breaker		138			Install 2 new circuit breakers, bus and associated equipment for the new 138kV circuit from Hillcrest.	OH			Planned	$1,602,070	Y		A
A	Central	DEM	91	358	6/1/2008	Hillcrest 345/138	transformer	1	345	138	450	Add new 345/138 transformer	OH			Planned	$4,120,000	Y		A
A	Central	DEM	91	362	6/1/2008	Hillcrest	Eastwood	1	138		304	Add new line	OH		8.0	Planned	$4,704,406	Y		A
A	Central	DEM	91	2537	6/1/2008	Brown	Relays		138			Replace relays at Brown on the 138kV lie to Eastwood associated with the new Hillcrest to Eastwood 138kV line.	OH			Planned	$210,608	Y		A
A	Central	DEM	91	2538	6/1/2008	Ford Batavia	Relays		138			Replace relays at Ford Batavia on the 138kV lie to Eastwood associated with the new Hillcrest to Eastwood 138kV line.	OH			Planned	$270,412	Y		A
A	Central	DEM	91	2539	6/1/2008	Stuart	Relays		345			Replace relays at Stuart on the 345kV line to the new Hillcrest substation.	OH			Planned	$93,403	Y	Y	A
A	Central	DEM	91	2540	6/1/2008	Foster	Relays		345			Replace relays at Foster on the 345kV line to the new Hillcrest substation.	OH			Planned	$213,385	Y	Y	A
A	Central	DEM	91	2556	6/1/2008	Hillcrest 345 kV	substation upgrades		345			345 kV upgrades for 345/138 transformer	OH			Planned	$6,473,212	Y	Y	A
A	Central	DEM	200	2567	6/1/2008	West LafayettePurdue	Purdue NW Tap		138		179	Uprate to 100C	IN			Planned	$9,878			A

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A	Central	DEM	618	1290	12/31/2009	Beckjord	(rebuild substation)		138			rebuild substation so it can be tied together under normal conditions	OH			Proposed	$1,738,266			A
A	Central	DEM	619	1292	6/1/2008	IPL Petersburg	345kV breaker		345			Complete breaker and half scheme at Petersburg Plant. IPL total estimate 1,100,000. 200k is Cinergy share of project.	IN			Planned	$200,000			A
A	Central	DEM	624	1300	12/31/2008	Cloverdale	Plainfield South	1	138		No change	Upgrade static and grounding	IN	24.3		Planned	$1,816,905			A
A	Central	DEM	627	1304	6/1/2009	Kenton	West End	1	138		239	Add new line	KY-OH	4.5	4.3	Planned	$1,980,041			A
A	Central	DEM	627	1853	6/1/2009	Buffington Reactor	Florence		138			Remove reactor when Kenton to West End project is completed.	KY			Planned				A
A	Central	DEM	627	1953	6/1/2009	Crescent	West End		138		239	3 wires of existing 6 wire circuit will be used for the new Kenton to West End circuit, lowering the rating of Crescent to West End.	KY			Planned				A
A	Central	DEM	632	1309	6/1/2009	Gallagher	HE Georgetown	1	138		202	reconducgtor 250CU, 477ACSR already 100C (no cost)	IN	2.8		Planned	$1,065,110			A
A	Central	DEM	807	812	6/1/2009	Dresser 345/138 Bk1	transformer	1	345	138	523	Upgrade limiting equipment to achieve full transformer rating	IN			Planned	$197,839			A
A	Central	DEM	807	813	6/1/2009	Dresser 345/138 Bk2	transformer	2	345	138	543	Upgrade limiting equipment to achieve full transformer rating	IN			Planned	$197,839			A
A	Central	DEM	839	818	11/2/2007	Crawfordsville	Capacitor		138		28.8 MVAR	Add capacitor	IN			Under Constr	$500,000			A
A	Central	DEM	849	823	12/31/2007	Peabody Jct	Jasonville	1	138		246	Replace Peabody Jct 600A switches with 1200A towards Jasonville in the 13821 line, 804F6402	IN			Under Constr	$159,171			A
A	Central	DEM	849	824	12/31/2007	Peabody Jct	Farmersburg Jct	1	138		246	Replace Peabody Jct 600A switches with 1200A towards Farmersburg Jct in the 13821 line, 804F6402	IN			Under Constr	$159,171			A
A	Central	DEM	851	826	6/1/2011	Lafayette Cumberland Ave	Laf AE Staley	1	138		306	13806 reconductor with 954ACSR 100C 604F6347	IN	1.3		Planned	$349,357			A
C>A	Central	DEM	852	827	12/31/2009	Lafayette Southeast	Tipmont Concord Jct	1	138		306	13819 reconductor with 954ACSR 100C 604F6351	IN	8.0		Planned	$1,125,284	Y		A
C>A	Central	DEM	852	1979	12/31/2009	Crawfordsville	Tipmont Concord Jct		138		306	13819 reconductor with 954ACSR 100C	IN	17.4		Planned	$6,142,189	Y		A
A	Central	DEM	1193	1843	6/1/2009	Nickel			138			Build new Nickel 138/13.09 kv sub to be built on development property - tap the 5680 line	OH			Planned	$150,377			A
A	Central	DEM	1198	1849	6/1/2008	Bedford			345			Add motors and automation to the 34506 and 34521 line switches.	IN			Planned	$152,390			A
A	Central	DEM	1199	1850	6/1/2010	Dresser	Terre Haute South 1st St	1	138		287	Uprate 13868 conductor to 100C operating temperature from Dresser to South 1st St. New limit 1200A terminal equipment.	IN			Planned	$10,000			A
A	Central	DEM	1199	1851	6/1/2010	Terre Haute South 1st St	Terre Haute Water St	1	138		287	Uprate 13868 conductor to 100C operating temperature from South 1st St to Water St. New limit 1200A terminal equipment.	IN			Planned	$10,000			A
A	Central	DEM	1200	1852	6/1/2010	Speed		3	345	138	520	Upgrade 2000A 138kV breaker & switch and any other Bk3 limiting equipment. Replace any equipment that would limit the 345/138 xfr to less than the hot spot rating of 520 MVA.	IN			Planned	$173,193			A
A	Central	DEM	1244	1945	6/1/2011	Cayuga 23013 Wave Trap	Frankfort		230		797	Replace 1600A wave trap with a 2000A wave trap. Increase line rating of the Cayuga to Frankfort 23013 line.	IN			Planned	$68,733			A
A	Central	DEM	1244	1946	6/1/2011	Frankfort 23013 Wave Trap	Cayuga		230		797	Replace 1600A wave trap with a 2000A wave trap. Increase line rating of the Cayuga to Frankfort 23013 line.	IN			Planned	$98,827			A
A	Central	DEM	1246	1947	6/1/2011	Five Points 23030 Wave Trap	Geist		230		405	Replace 800A wave trap with a 2000A wave trap. Increase line rating to Geist.	IN			Planned	$24,038			A
A	Central	DEM	1247	1948	6/1/2011	Greentown	Peru SE		230		478	Uprate 23021 circuit to 100C operating temp	IN			Planned	$28,403			A

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A	Central	DEM	1251	1950	6/1/2011	Noblesville 23008 Wave Trap	Carmel 146th St Jct		230		405	Replace 800A wave trap with a 2000A wave trap. Increase 230kV line rating to Carmel 146th St Jct.	IN			Planned	$24,038			A
A	Central	DEM	1253	1952	6/1/2011	Noblesville 23007 Wave Trap	Geist		230		405	Replace 800A wave trap with a 2000A wave trap. Increase line rating to Geist.	IN			Planned	$24,038			A
A	Central	DEM	1254	1955	12/31/2009	Charlestown	CMC		138		306	Construct 8.5 mi. of 138kV line from Charlestown to CMC.	IN		8.5	Planned				A
A	Central	DEM	1262	1978	6/1/2008	HE Durgee Rd			138			HE 138/12 kV substation.	IN			Planned	$227,341			A
B>A	Central	DEM	1263	1980	5/30/2011	Edwardsport 345 kV Sub			345			New 345 kV ring bus switching station, This LGIA to include five (5) 345 kV, 3000A, 50 kA circuit breakers, 2 sets of 345 kV interconnection metering, foundations, steel structures, grounding, relaying, control cables, and associated equipment.	IN			Planned	$6,037,000	Y	Y	A
B>A	Central	DEM	1263	2570	5/30/2011	Edwardsport 345 kV sub			345			345 kV Extension – Loop the Wheatland-Amo 345 kV circuit into the New 345 kV ring bus switching station. Utilize Bundled 954 kcm ACSR 45X& phase conductors and 3/8ST7 static wires.	IN			Planned	$1,200,000	Y	Y	A
B>A	Central	DEM	1263	2571	5/30/2011	Amo 345 kV sub			345			Amo Station – On the 345 kV circuit to the New 345 kV ring bus switching station (formerly the Wheatland-Amo 345 kV circuit), upgrade the primary and back-up relaying and carrier facilities.	IN			Planned	$175,000	Y	Y	A
B>A	Central	DEM	1263	2572	5/30/2011	Wheatland 345 kV sub			345			Wheatland Station – On the 345 kV circuit to the New 345 kV ring bus switching station (formerly the Wheatland-Amo 345 kV circuit), upgrade the primary and back-up relaying and carrier facilities.	IN			Planned	$175,000	Y	Y	A
A	East	FE	615	1283	11/1/2007	Gallion	138 kV bus		138			Breaker Addition	OH			Under Constr	$1,815,566			A
A	East	FE	890	899	6/1/2008	North Medina new 345-138 kV	substation	4	345	138		Add a new 345/138kV substation at the junction of the Star-Carlisle 345kV and Star-West Akron #2 138kV lines	OH			Planned	$8,300,000	Y		A
A	East	FE	890	2559	6/1/2008	North Medina 345 kV	substation upgrades		345			North Medina 345 kV substation	OH			Planned	$3,540,000	Y	Y	A
A	East	FE	1326	2191	6/1/2008	Harding	capacitor bank		345			Capacitor Bank Addition	OH			Planned	$3,800,000	Y	Y	A
A	East	FE	1326	2192	6/1/2008	Juniper	capacitor bank		345			Capacitor Bank Addition	OH			Planned	$3,200,000	Y	Y	A
A	East	FE	1327	2193	6/1/2009	Babb	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$873,300			A
A	East	FE	1328	2194	6/1/2010	Barberton	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$677,600			A
A	East	FE	1329	2195	6/1/2010	West Akron	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$257,000			A
A	East	FE	1330	2196	6/1/2007	South Akron	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$526,288			A
A	East	FE	1331	2197	6/1/2011	East Akron	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$305,000			A
A	East	FE	1332	2198	6/1/2008	Cloverdale	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$632,021			A
A	East	FE	1333	2199	6/1/2010	Brookside	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$1,000,200			A
A	East	FE	1334	2200	6/1/2010	Longview	capacitor bank		138			Capacitor Bank Addition	OH			Planned	$523,800			A
A	West	GRE	599	753	6/1/2009	Crooked Lake	Enterprise Park	1	115		142		MN		3.5	Proposed	$3,600,000			A
A	West	GRE	600	1078	12/1/2008	Baxter	Southdale	1	115		224		MN		9.0	Planned	$3,500,000			A
A	West	GRE	601	641	12/1/2008	Mud Lake	Wilson Lake	1	115		142		MN	12.0		Planned	$6,000,000			A
A	West	GRE	1026	752	6/1/2008	Linwood 230-69 kV	transformer	1	230	69	112		MN			Planned	$5,000,000			A
A	West	GRE	1459	2499	5/1/2010	Dakota County Sub	transformer	1	345	16	224 MVA	one 224 MVA, 345/16 kV generator step-up transfo	MN			Planned	$275,000			A
A	West	GRE	1459	2500	5/1/2010	Dakota County Sub	transformer	2	345	16	224 MVA	one 224 MVA, 345/16 kV generator step-up transfo	MN			Planned	$275,000			A
A	West	GRE	1459	2501	5/1/2010	Dakota County Sub	new substation		345			new substation, along with NSP Blue Lake and Prairie Island transmission line construction	MN			Planned	$5,959,788	Y	Y	A
A	Central	HE	204	171	6/1/2009	Batesville	Tapline w/ substation	1	138	13		New Construction, taps Duke 13833	IN		0.5	Proposed	$950,000			A
A	Central	HE	204	179	6/1/2009	North Charleston	Tapline w/ substation	1	138	13		New Construction, taps Duke 13857	IN		0.1	Proposed	$900,000			A

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A	Central	HE	1318	2171	9/1/2007	Decatur County Switch Station (DCSS)	138kV Switching Station w/Capacitor	1	138		30MVAR	New Construction	IN			Planned	$3,000,000			A
A	Central	HE	1318	2172	9/1/2007	Decatur County Switch Station (DCSS)	161/138kV Transformer	1	161	138	250MVA	New Construction	IN			Planned	$1,000,000			A
A	Central	HE	1318	2173	9/1/2007	Decatur County Switch Station (DCSS)	138kV 6-Breaker Ringbus	1	138		2000Amp	New Construction	IN			Planned	$3,000,000			A
A	Central	HE	1319	2174	9/1/2007	Decatur County Switch Station (DCSS)	Cinergy 138 (Greensburg to Shelbyville)	1	138		327MVA	New Construction	IN		0.5	Planned	$500,000			A
A	Central	HE	1320	2175	9/1/2007	Greensburg Honda	138/12.47kV Substation	1	138	12.5	56MVA	New Construction	IN			Planned	$2,750,000			A
A	Central	HE	1320	2176	9/1/2007	Greensburg Honda	138/12.47kV Substation	2	138	12.5	56MVA	New Construction	IN			Planned	$2,750,000			A
A	Central	HE	1320	2177	9/1/2007	Greensburg Honda	DCSS	1	138		215MVA	New Construction East Loop	IN		5.5	Planned	$1,875,000			A
A	Central	HE	1320	2178	9/1/2007	Greensburg Honda	DCSS	1	138		215MVA	New Construction West Loop	IN		5.5	Planned	$1,875,000			A
A	Central	HE	1321	2179	9/1/2008	Napoleon	Capacitor & CB Addition, and bus upgrades	1	161		30MVAR	New Construction	IN			Planned	$800,000			A
A	Central	HE	1321	2180	9/1/2008	Napoleon Primary	DCSS	1	161		338MVA	New Construction	IN		25.0	Planned	$7,200,000			A
A	Central	HE	1322	2181	4/1/2008	Owensville Primary		1	138	69	150MVA	New Construction	IN			Planned	$5,500,000			A
A	Central	HE	1322	2182	4/1/2008	Owensville Primary Tapline	Cinergy 138 (Gibson to Princeton)	1	138		215MVA	New Construction	IN		0.5	Planned	$2,500,000			A
A	Central	IPL	40	177	6/1/2008	Indian Creek	Julietta	1	138		286 MVA	New 138kV Line	IN		5.0	Planned	$2,500,000			A
A	Central	IPL	40	178	6/1/2008	Cumberland	Julietta	1	138		286 MVA	New 138kV Line	IN		4.6	Planned	$2,500,000			A
A	Central	IPL	893	902	6/1/2009	North	Capacitor		138		150 MVAR	Increase Capacitor Size To 150 MVAR	IN			Planned	$300,000			A
A	Central	IPL	895	904	12/1/2007	North	Breaker		138		245 MVA	New 2000 Amp Breaker	IN			Under Constr	$1,350,000			A
A	Central	IPL	895	905	12/1/2007	North	Breaker		138		245 MVA	New 2000 Amp Breaker	IN			Under Constr	$1,350,000			A
A	East	ITC	518	770	10/31/2007	Golf 120	Boyne 120	1	120		290		MI	4.2	0.6	Under Constr	$1,200,000			A
A	East	ITC	518	771	10/31/2007	Golf 120	Houston 2 120	1	120		313		MI	17.3		Under Constr	$1,200,000			A
A	East	ITC	518	773	10/31/2007	Golf 120	Macomb 120 #2	2	120		291		MI	3.2		Under Constr	$1,600,000			A
A	East	ITC	686	1381	12/31/2007	Majestic 120 kV	Lark 120 kV	1	120		313		MI	2.6	9.2	Planned	$2,700,000			A
A	East	ITC	686	1382	12/31/2007	Majestic 120 kV	Phoenix 120 kV	1	120		313		MI	7.4	9.2	Planned	$3,500,000			A
A	East	ITC	692	1383	12/31/2009	Bismarck 345 kV	Troy 345 kV	1	345		700		MI		15.4	Planned	$145,000,000	Y	Y	A
A	East	ITC	692	1384	12/31/2009	Troy 345/120 kV	transformer	1	345	120	700		MI			Planned	$5,000,000	Y		A
A	East	ITC	905	929	12/31/2007	Bunce Creek 120 kV	Wabash 120 kV 2	2	120		299		MI	0.1		Planned	$1,166,666			A
A	East	ITC	905	930	12/31/2007	Bunce Creek 120 kV	Menlo 120 kV	1	120		152		MI	0.1		Planned	$1,166,666			A
A	East	ITC	905	931	12/31/2007	Bunce Creek 120 kV	Cypress 120 kV	1	120		313		MI	0.1		Planned	$1,166,668			A
A	East	ITC	907	910	12/31/2009	Goodison 345 kV	Belle River 345	1	345		2151	Goodison 345 kV substation	MI	35.2		Planned	$6,000,000	Y	Y	A
A	East	ITC	907	911	12/31/2009	Goodison 345 kV	Pontiac 345	1	345		2002	Goodison 345 kV substation	MI	6.3		Planned	$6,000,000	Y	Y	A
A	East	ITC	907	912	12/31/2009	Goodison 345/120 kV	transformer	1	345	120	700		MI			Planned	$5,000,000	Y		A
A	East	ITC	907	913	12/31/2009	Goodison 120 kV	Pontiac 120 kV	1	120		343		MI		6.3	Planned	$11,000,000	Y		A
A	East	ITC	907	914	12/31/2009	Goodison 120 kV	Sunbird 120 kV	1	120		229		MI	3.6	2.9	Planned	$11,000,000	Y		A
A	East	ITC	907	915	12/31/2009	Goodison 120 kV	Tienken 120 kV	1	120		343		MI	2.8	2.3	Planned	$9,000,000	Y		A
A	East	ITC	907	916	12/31/2009	Spokane 120 kV	Tienken 120 kV	1	120		343		MI	0.1		Planned	$2,000,000	Y		A
A	East	ITC	910	950	12/31/2007	Coventry 345/230	transformer	1	345	230	782		MI			Under Constr	$8,200,000	Y		A
A	East	ITC	910	951	12/31/2007	Cody 230/120 kV	transformer	1	230	120	693		MI			Under Constr	$4,500,000	Y		A
A	East	ITC	910	952	12/31/2007	Coventry 230 kV	Cody 230kV	1	230		657		MI	6.6		Under Constr	$3,000,000	Y		A
A	East	ITC	910	1581	12/31/2007	Coventry 230 kV	Wixom 230 kV	1	230			345 kV operated at 230 kV	MI			Under Constr	$7,000,000	Y		A
A	East	ITC	910	2560	12/31/2007	Coventry 345 kV	substation	1	345			345 kV substation upgrades	MI			Under Constr	$2,900,000	Y	Y	A
A	East	ITC	911	953	12/31/2007	Placid 345 kV	transformer	2	345	120	700	120 kV bus work	MI			Under Constr	$350,000	Y		A
A	East	ITC	911	2561	12/31/2007	Placid 345 kV	substation		345			345 kV substation upgradeds	MI			Under Constr	$5,200,000	Y	Y	A
A	East	ITC	1011	1583	12/31/2007	Genoa 120 kV	Durant 120 kV	1	120		343		MI		8.5	Under Constr	$15,000,000			A
A	East	ITC	1301	2132	12/31/2008	Yost 120 kV	Polaris 120 kV	1	120		349	line breaker	MI	0.9		Planned	$300,000			A
A	East	ITC	1302	2133	12/31/2007	Hines 120 kV	substation equipment		120		642	station equipment replacement	MI			Planned	$750,000			A
A	East	ITC	1309	2142	12/31/2007	Monroe 345 kV pos. CF	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2143	12/31/2007	Monroe 345 kV pos. CM	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2144	12/31/2007	Monroe 345 kV pos. CT	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2145	12/31/2007	Monroe 345 kV pos. LF	circuit breaker		345			CB replacement	MI			Planned	$250,000			A

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A	East	ITC	1309	2146	12/31/2007	Monroe 345 kV pos. LM	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2147	12/31/2007	Monroe 345 kV pos. LT	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2148	12/31/2007	Monroe 345 kV pos. FF	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2149	12/31/2007	Monroe 345 kV pos. FM	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2150	12/31/2007	Monroe 345 kV pos. FT	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2151	12/31/2007	Monroe 345 kV pos. BF	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2152	12/31/2007	Monroe 345 kV pos. BM	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1309	2153	12/31/2007	Monroe 345 kV pos. BT	circuit breaker		345			CB replacement	MI			Planned	$250,000			A
A	East	ITC	1310	2154	12/31/2007	Waterman 230 kV pos. BF	circuit breaker		230			CB replacement	MI			Planned	$200,000			A
A	East	ITC	1310	2155	12/31/2007	Waterman 230 kV pos. CF	circuit breaker		230			CB replacement	MI			Planned	$200,000			A
A	East	ITC	1310	2156	12/31/2007	Warren 230 kV pos. CF	circuit breaker		230			CB replacement	MI			Planned	$200,000			A
A	East	ITC	1310	2157	12/31/2007	St. Clair 120 kV pos. JD	circuit breaker		120			CB replacement	MI			Planned	$200,000			A
A	East	ITC	1310	2158	12/31/2007	St. Clair 120 kV pos. KB	circuit breaker		120			CB replacement	MI			Planned	$150,000			A
A	East	ITC	1310	2159	12/31/2007	St. Clair 120 kV pos. HS	circuit breaker		120			CB replacement	MI			Planned	$150,000			A
A	East	ITC	1310	2160	12/31/2007	Trenton Ch. 120 kV Pos. KG	circuit breaker		120			CB replacement	MI			Planned	$150,000			A
A	East	ITC	1310	2161	12/31/2007	Trenton Ch. 120 kV Pos. KP	circuit breaker		120			CB replacement	MI			Planned	$150,000			A
A	East	ITC	1310	2162	12/31/2007	Wabash 120 kV pos. HL	circuit breaker		120			CB replacement	MI			Planned	$150,000			A
A	East	ITC	1310	2163	12/31/2007	Polaris 120 kV pos. HG	circuit breaker		120			CB replacement	MI			Planned	$150,000			A
A	East	ITC	1310	2164	12/31/2007	Atlanta 120 kV pos. HD	circuit breaker		120			CB replacement	MI			Planned	$150,000			A
A	East	ITC	1310	2165	12/31/2007	Brock 120 kV pos. HP	circuit breaker		120			CB replacement	MI			Planned	$150,000			A
A	East	ITC	1488	1584	6/1/2008	Placid 120 kV	Durant 120 kV	1	120		343	Should have te same PrjID as Genoa-Durant (1011)	MI	16.7		Planned	$4,000,000			A
A	East	ITC	1488	1585	6/1/2008	Placid 120 kV	Proud 120 kV	1	120		343	Should have te same PrjID as Genoa-Durant (1011)	MI	14.3		Planned				A
A	West	MDU	548	1576	11/1/2007	Bismarck Downtown	East Bismarck		115		160	Rebuild	ND			Planned	$363,000			A
A	West	MDU	1008	1577	11/1/2009	Heskett	NW Bismarck		115		180	Memorial Bridge circuit replacement	ND			Planned	$3,692,000			A
A	West	MDU	1008	1578	11/1/2009	S Mandan	Bismarck Downtown		115		180	Memorial Bridge circuit replacement	ND			Planned	$2,868,000			A
A	East	METC	481	1332	12/1/2008	Tallmadge 3rd 345/138 kV	transformer	3	345	138			MI			Planned	$3,649,203	Y		A
A	East	METC	481	1534	12/1/2008	Tallmadge Remove Reactors	Tallmadge Remove Reactors	1&2	345			remove 138 kV reactors	MI			Planned	$0	Y		A
A	East	METC	481	2557	12/1/2008	Tallmadge 345 kV	substation upgrades		345			sub upgrades for 3rd transformer	MI			Planned	$6,263,887	Y	Y	A
A	East	METC	497	1322	6/1/2007	Tallmadge	Wealthy	2	138				MI			Planned	$40,000			A
A	East	METC	658	1345	5/1/2008	Gaylord	Livingston	1	138				MI	1.5		Planned	$500,000			A
A	East	METC	660	1347	5/1/2009	Keystone	Clearwater	1	138				MI	23.2		Planned	$10,200,000	Y		A
A	East	METC	740	1434	3/1/2009	Gallagher	Tittabawassee	1	345			relaying & communications	MI			Planned	$1,000,000			A
A	East	METC	740	1435	3/1/2009	Keystone	Livingston	1	345			relaying & communications	MI			Planned	$1,000,000			A
A	East	METC	740	1436	3/1/2009	Livingston	Gallagher	1	345			relaying & communications	MI			Planned	$794,000			A
A	East	METC	981	1544	6/1/2009	Wabasis J. - N. Belding - Vergennes	Wabasis	1	138			Install aTap Pole and Switches	MI			Planned	$160,000			A
A	East	METC	988	1551	12/31/2009	Simpson	Batavia	1	138				MI		30.0	Planned	$13,000,000	Y		A
A	East	METC	1015	1587	6/1/2008	Oden	Oden - New Capacitor	1	138		21.6 Mvar	Oden - New 21.6 Mvar Capacitor	MI			Planned	$510,000			A
A	East	METC	1016	1588	6/1/2008	Bard Road	Bard Road - New Capacitor	1	138		36 Mvar	Bard Road - New 36 Mvar Capacitor	MI			Planned	$596,000			A
A	East	METC	1017	1589	6/1/2008	Croton	Croton - New Capacitor	1	138		36 Mvar	Croton - New 36 Mvar Capacitor	MI			Planned	$596,000			A
A	East	METC	1390	2393	12/1/2007	Goss 345kV	345kV GIS bus and breakers		345			Replace old, leaking 345kV GIS bus & breakers wi	MI			Planned	$5,800,000			A
A	East	METC	1391	2394	12/31/2007	Campbell 138kV	Breaker 148		138			Replace overdutied breaker with higher capacity bı	MI			Planned	$160,000			A
A	East	METC	1392	2395	12/31/2007	Campbell 138kV	Breaker 188		138			Replace overdutied breaker with higher capacity bı	MI			Planned	$160,000			A
A	East	METC	1393	2396	12/31/2007	Campbell 138kV	Breaker 288		138			Replace overdutied breaker with higher capacity bı	MI			Planned	$160,000			A
A	East	METC	1394	2397	12/31/2007	Campbell 138kV	Breaker 388		138			Replace overdutied breaker with higher capacity bı	MI			Planned	$160,000			A
A	East	METC	1395	2398	12/31/2007	Campbell 138kV	Breaker 500		138			Replace overdutied breaker with higher capacity bı	MI			Planned	$160,000			A
A	East	METC	1396	2399	12/31/2007	Campbell 138kV	Breaker 588		138			Replace overdutied breaker with higher capacity bı	MI			Planned	$160,000			A

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A	East	METC	1397	2400	12/31/2007	Spaulding 138kV	Breaker 36M9		138			Replace overdutied breaker with higher capacity b	MI			Planned	$160,000			A
A	East	METC	1398	2401	12/31/2007	Spaulding 138kV	Breaker 36B7		138			Replace overdutied breaker with higher capacity b	MI			Planned	$160,000			A
A	East	METC	1399	2402	12/31/2007	Morrow 138kV	Breaker 377		138			Replace overdutied breaker with higher capacity b	MI			Planned	$160,000			A
A	East	METC	1400	2403	12/31/2007	Claremont 138kV	Breaker 288		138			Replace overdutied breaker with higher capacity b	MI			Under Constr	$160,000			A
A	East	METC	1401	2404	12/31/2007	Claremont 138kV	Breaker 388		138			Replace overdutied breaker with higher capacity b	MI			Under Constr	$160,000			A
A	East	METC	1402	2405	12/31/2007	Goss 138kV	Breaker 13B7		138			Replace overdutied breaker with higher capacity b	MI			Planned	$160,000			A
A	East	METC	1403	2406	12/31/2007	Goss 138kV	Breaker 13M9		138			Replace overdutied breaker with higher capacity b	MI			Planned	$160,000			A
A	East	METC	1404	2407	12/31/2007	Argenta 138kV	Breaker 6W8		138			Replace overdutied breaker with higher capacity b	MI			Planned	$160,000			A
A	East	METC	1405	2408	12/31/2007	Hemphill 138kV	Breaker 499		138			Replace overdutied breaker with higher capacity b	MI			Planned	$160,000			A
A	East	METC	1406	2409	12/31/2008	Alpena 138kV	Breaker 188		138			Replace overdutied breaker with higher capacity b	MI			Planned	$160,000			A
A	East	METC	1407	2410	12/1/2007	Ludington 345kV	Reactor		345			Repair or replace existing 100MVAR reactor and replace circuit switcher with a breaker	MI			Planned	$1,500,000			A
A	East	METC	1408	2411	5/1/2007	RTU/SCADA upgrades	Throughtout System		345	138		Install and/or upgrade numerous RTU/SCADA points	MI			Under Constr	$801,000			A
A	East	METC	1410	2413	12/1/2008	Mobile 138kV Capacitor			138		14.4 - 36MVAR	Purchase a mobile 138kV capacitor for use where needed during outages, heavy transfers, etc.	MI			Planned	$700,000			A
A	East	METC	1412	2416	11/1/2007	Palisades 345kV	Cook 345kV	2	345			Modify phase connections at the Palisades and Cook ends of the 345kV line for Covert project	MI			Planned	$735,000			A
A	East	METC	1413	2417	5/1/2009	Bagley 138kV	Gaylord 138kV	1	138			Rebuild line to 795 ACSS	MI			Planned	$350,000			A
A	East	METC	1414	2418	12/31/2007	Thetford 345kV	Line Relaying		345			Upgrade 345kV line relaying.	MI			Planned	$300,000			A
A	East	METC	1415	2419	10/1/2007	HSC 138kV	Tittabawasee 138kV & Lawndale 138kV	1	138			Install a tap pole and one switch on each of the Tittabawassee-HSC and Lawndale-HSC 138kV lines. (Solar Project)	MI			Under Constr	$160,000			A
A	East	METC	1416	2420	10/1/2007	HSC 138kV	Tittabawasee 138kV & Lawndale 138kV	1	138			Install a new 2-mile 138kV double circuit to swap the existing 138kV Tittabawasee and Lawndale line connections into HSC. (HSC Project)	MI			Under Constr	$2,700,000	Y		A
A	East	METC	1416	2421	10/1/2007	HSC 138kV	Tittabawasee 138kV	2	138			Install new,second 138kV Tittabawasee-HSC line and 5 total 138kV breakers for connecting the line at each end. (HSC Project)	MI			Under Constr	$4,527,000	Y		A
A	East	METC	1419	2424	7/31/2007	Hackett Junction 138kV	Saginaw River 138kV	1	138			Install a Tap Pole and one Switch (Laundra)	MI			Under Constr	$80,000			A
A	East	METC	1420	2425	11/1/2007	North Belding 138kV	Sanderson Junction 138kV	1	138			Install a Tap Pole and one Switch (Sanderson)	MI			Planned	$80,000			A
A	East	METC	1421	2426	12/15/2007	Michigan Junction 138kV	Race Street Junction 138kV	1	138			Install a 138kV tie-breaker and loop the Spaulding-Four Mile 138 kV Line into new Baraga substation (Baraga)	MI			Planned	$240,000			A
A	East	METC	1422	2427	6/1/2007	Marshall 138kV	Hughes Junction 138kV	1	138			Install a Tap Pole and one Switch (Marshall)	MI			Planned	$80,000			A
A	East	METC	1423	2428	6/1/2007	Emmet 138kV	McNally 138kV	1	138			Install a tap pole and two switches on the Emmet-McNally 138kV line. Purchase the high side of Emmet Substation and a section of the 138kV line from the substation to the Eppler tap point. (Eppler)	MI			Planned	$500,000			A
A	East	METC	1425	2430	6/1/2008	Keystone 138kV	Elmwood 138kV	1	138			Install a Tap Pole and Switches. Relay upgrades. (Gray Rd)	MI			Planned	$300,000			A
A	East	METC	1433	2437	6/1/2008	Beals 138kV	Hazelwood 138kV	1	138			Install bulk substation served from the Beals-Hazelwood 138kV Line (Buskirk)	MI			Planned	$2,200,000			A
A	East	METC	1434	2438	6/1/2008	Spaulding 138kV			138			Install bulk substation served from the Spaulding 138kV ring bus (Five Mile)	MI			Planned	$750,000			A
A	East	METC	1437	2441	6/1/2008	Argenta 138kV	Milham 138kV	1	138			Install a tap pole and two switches on Argenta-Milham 138kV Line (N Ave)	MI			Planned	$160,000			A
A	East	METC	1438	2442	6/1/2008	Wexford 138kV	Tippy 138kV	1	138			Install a tap pole and one switch on Wexford-Tippy 138kV Line (Potvin)	MI			Planned	$80,000			A
A	East	METC	1439	2443	10/1/2007	Hemphill 138kV	Weadock 138kV	1	138			Install a tap pole and two switches on Hemphill-Weadock 138kV Line (Busch)	MI			Planned	$160,000			A

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A	East	METC	1440	2444	6/1/2008	Beals 138kV	Wayland 138kV	1	138			Install a tap pole and two switches on Beals Rd-Wayland-Hazelwood 138kV Line (Huckleberry)	MI			Planned	$80,000			A
A	East	METC	1441	2445	6/1/2009	Sternberg 138kV			138			Install bulk substation served from a new Ellis spur from Sternberg (Ellis/Hile Rd)	MI			Planned	$3,250,000			A
A	East	METC	1442	2446	10/1/2007	Fillmore 138kV	Four Mile 138kV	1	138			Install bulk substation served from the Fillmore-Four Mile 138kV Line (Eastmanville/Pingree)	MI			Planned	$200,000			A
A	East	METC	1444	2448	6/1/2011	Bullock 138kV	Edenville Junction 138kV	1	138			Install a tap pole and two switches on Bullock-Edenville 138kV Line (Dublin)	MI			Planned	$160,000			A
A	East	METC	1445	2449	6/1/2010	Emmet 138kV	distribution		138			Install a second distribution transformer at Emmet (Emmet)	MI			Planned	$2,750,000			A
A	East	METC	1446	2450	6/1/2010	Gaines 138kV			138			Install bulk substation at Gaines (Gaines)	MI			Planned	$50,000			A
A	East	METC	1447	2451	6/1/2010	Eureka 138kV	Vestaburg 138kV	1	138			Install bulk substation served from the Eureka-Deja-Vestaburg 138kV Line (Horseshoe Creek/Deja)	MI			Planned	$2,200,000			A
A	East	METC	1449	2453	6/1/2010	Cobb 138kV	Tallmadge 138kV	2	138			Install bulk substation served from the Cobb-Tallmadge #2 138kV Line (Juniper)	MI			Planned	$160,000			A
A	West	MP	1	318	6/30/2008	Arrowhead 230-230 kV	Phase-Shifter	1	230	230	800		MN			Planned	$13,741,773			A
A	West	MP	1	319	6/30/2008	Arrowhead 345/230 kV	transformer	1	345	230	800		MN			Planned	$10,400,000			A
A	West	MP	1	2039	6/30/2008	Arrowhead	Capacitor		230		2 x 75 Mvar		MN			Planned	$1,858,227			A
C>A	West	MP	1025	2659	7/1/2012	Blackberry 230			230			Blackberry Sub: 3 each-230 kV circuit breakers, 9 each-230 kV air break switches, structural steel, bus work and control equipment	MN			Planned	$3,163,583	Y		A
C>A	West	MP	1025	2660	7/1/2012	Boswell 230	Swatara 230		230			Boswell to Swatara 34.6 Miles	MN			Planned	$34,069,591	Y		A
C>A	West	MP	1025	2661	7/1/2012	Swatara 230	Riverton 230		230			Swatara to Riverton 33.2 Miles	MN			Planned	$24,878,937	Y		A
C>A	West	MP	1025	2662	7/1/2012	Blackberry 230 kV sub			230			230 kV Bus Position for Boswell-Riverton Line at Boswell	MN			Planned	$3,017,108	Y		A
C>A	West	MP	1025	2663	7/1/2012	Swatara 230/115 kV	transformer		230	115		New 230/115 kV Swatara Substation	MN			Planned	$8,817,640	Y		A
C>A	West	MP	1025	2664	7/1/2012	Riverton 230 kV sub			230			230 kV Bus Position for Boswell-Riverton Line at Riverton	MN			Planned	$2,372,682	Y		A
B>A	West	MP	1286	2115	6/1/2008	Two Harbors	capacitor		115		25 Mvar	New Switching station & 25 MVAR cap	MN			Planned	$1,750,000			A
B>A	West	MP	1359	2260	6/30/2007	International Falls	Capacitor		115		1x20 Mvar	add new	MN			Planned	$245,000			A
C>A	West	MP/GRE	277	2263	5/1/2009	Badoura	Pine River	1	115		182		MN		19.8	Planned	$8,330,836			A
B>A	West	MP/GRE	277	579	5/1/2010	Pine River	Pequot Lakes	1	115		182		MN		8.9	Planned	$5,565,190	Y		A
C>A	West	MP/GRE	1021	1590	11/1/2009	Embarrass 115	Tower 115	1	115		182	New 115 kV line	MN		15.0	Planned	$7,314,000			A
B>A	West	MP/GRE	1022	1591	5/1/2009	Badoura 115	Long Lake 115	1	115		182	New 115 kV line	MN		17.0	Under Constr	$8,621,000	Y		A
C>A	West	MP/GRE	1361	2264	12/31/2009	Badoura	Birch Lake	1	115		182		MN		16.0	Planned	$9,330,545			A
A	West	XEL/OTP/MP/M	279	1098	7/1/2010	Boswell	Wilton	1	230		495	Add a new 230 kV line between Boswell and Wilton	MN		72.0	Proposed	$72,360,000			A
A	West	MRES	755	3032	6/1/2008	Alexandria Switching Station	Capacitors		115		25 Mvar	Add a 1 x 25 MVAr capacitor bank at the Alexandria Switching Station	MN			Planned	$530,000			A
B>A	East	NIPS	612	1279	5/1/2008	Hiple	transformer	2	345	138	560	Add 2nd 345/138 kV Transformer	IN			Proposed	$5,799,614	Y	Y	A
A	East	NIPS	757	3034	12/1/2007	Dune Acres	Capacitor		138			Add Capacitor - (1) 100 MVAR step	IN			Planned	$1,083,600			A
A	East	NIPS	925	970	8/1/2007	ISG2	Marktown	1	138		316	Upgrade Connections and Circuit	IN	0.6		Under Constr	$240,500			A
A	East	NIPS	1298	2128	5/1/2008	Inland #5	Marktown	1	138		316/380	Upgrade Connections and Circuit	IN	2.2		Planned	$750,000			A
C>A	East	NIPS	1615	2665	10/31/2007	Goodland 69 kV	Remington 69 kV		69			Reconductoring of 69 kV circuit 6966, which consists of wood pole construction on public right-of-way, from Transmission Owner's Goodland Substation to its Remington Substation (approximately 5.1 miles)	IN			Planned	$870,000	Y		A
C>A	East	NIPS	1615	2667	10/31/2007	Morrison Ditch 138 kV (New sub)			138			Amount related to 138 kV Ring Bus Interconnection Substation	IN			Planned	$400,000	Y		A
C>A	East	NIPS	1615	2668	10/31/2007	Morrison Ditch and Goodland 138 kV subs			138			Protection and Relay($930,000), 138XX and 138YY Line Extensions 900 MCM ACSR with Static Wire ($60,000)	IN			Planned	$990,000	Y		A

MTEP07 Appendix A: Approved Projects - Facility Table - 10/04/07

App ABC	Region	Reporting Source	PrjID	Facil ID	Expected ISD	From Sub	To Sub or Equipment	Ckt	High kV	Low kV	Ratings	Upgrade Description	State	Miles Upg	Miles New	Planning Status	Estimated Cost	C.S.	P.S.	M07 ABC
A	West	OTP	274	377	8/1/2008	Appleton	Louisburg	1	115		96	Convert an existing 41.6 kV line to 115 kV	MN	6.9		Planned	$458,020			A
A	West	OTP	274	2266	8/1/2008	Louisurg	Dawson Tap	1	115		96	Convert an existing 41.6 kV line to 115 kV	MN	14.4		Planned	$954,580			A
A	West	OTP	274	2267	8/1/2008	Louisburg	transformer	1	115	12.5	10	Convert an existing 41.6 kV line to 115 kV	MN			Planned	$300,000			A
A	West	OTP	274	2268	8/1/2008	Dawson	transformer	1	115	12.5	20	Convert an existing 41.6 kV line to 115 kV	MN			Planned	$300,000			A
A	West	OTP	274	2598	8/1/2008	Dawson Tap	Dawson	1	115		96	Convert an existing 41.6 kV line to 115 kV	MN	1.0		Planned	$68,000			A
A	West	OTP	275	378	8/1/2008	Dawson Tap	Canby	1	115		96	Convert an existing 41.6 kV line to 115 kV	MN	21.1		Planned	$519,400			A
A	West	OTP	1462	2514	9/1/2007	Rugby	radial line		230			The new 230 KV overhead radial transmission line	ND		9.0	Planned	$88,000			A
A	West	OTP	1462	2515	9/1/2007	Rugby	bus		230			The Transmission Owner Interconnection Facilities	ND			Planned	$104,809			A
A	West	OTP	1462	2516	9/1/2007	Rugby	substation		230			The Transmission Owner will upgrade the Rugby S	ND			Planned	$705,931	Y		A
A	Central	SIPC	81	60	6/1/2007	Marion	CarrierMills	1	161		286		IL		27.0	Planned	$7,083,000			A
A	Central	Vectren	1004	1569	7/9/2007	Francisco 345/138 kV	Substation	1	345	138	448/470 MVA	new substation with one 345/138 transformer and 345 kV interconnection with Cinergy on Gibson-Duff line	IN			Under Constr	$16,000,000	Y		A
A	Central	Vectren	1257	1972	5/31/2011	AB Brown	Gibson (Duke)	15	345		1430/1430	new line	IN		40.0	Planned	$39,400,000	Y	Y	A
A	Central	Vectren	1257	1973	5/31/2011	AB Brown	Reid (BREC)	17	345		1430/1430	new line	IN/KY		24.0	Planned	$26,600,000	Y	Y	A
A	Central	Vectren	1259	1975	7/1/2007	Dubois	Newtonville	78	138		287/287	new line	IN		28.0	Under Constr	$14,400,000	Y		A
A	East	WPSC	1208	1903	12/31/2007	Oden	12MVAR cap. Bank		69			Add 12MVAR at Oden Sub.	MI			Planned	$300,000			A
A	East	WPSC	1226	1926	2/1/2008	Kalkaska Generation	Westwood	1	69		102.4	Rebuild 69 kV Line	MI	11.6		Planned	$2,905,000			A
A	East	WPSC	1227	1927	2/1/2008	Gaylord Generation	Bagley Junction	1	69		102.4	Rebuild 69 kV Line	MI	4.0		Planned	$1,000,000			A
A	East	WPSC	1228	1928	8/1/2008	Westwood	New Load		69			Add 14MW Load to Westwood	MI			Planned	$1,800,000			A
A	East	WPSC	1229	1929	12/31/2007	Plains X	Bus Upgrade		69			Upgrade exsisting 69KV bus	MI			Planned	$625,000			A
A	East	WPSC	1230	1930	7/31/2007	White Cloud	Bus Upgrade		69			Upgrade exsisting 69KV bus	MI			Planned	$625,000			A
A	East	WPSC	1272	1994	8/1/2010	Redwood 138	Redwood 69		138	69	75MVA	Add 75MV transformer	MI			Planned	$1,900,000			A
A	East	WPSC	1465	2527	10/1/2007	Donaldson Creek Sub	interconnection upgrades		138			The 138 kV double circuit line with one side operat	MI			Planned	$164,997			A
A	East	WPSC	1465	2528	10/1/2007	Donaldson Creek Sub	radial line		138			Construction of a new 138 kV transmission line fro	MI		6.0	Planned	$1,080,000			A
A	East	WPSC	1465	2529	10/1/2007	Donaldson Creek Sub	network upgrades		138			138 kV circuit breakers at POI, Below Grade Devel	MI			Planned	$845,291	Y		A
A	East	WPSC	1465	2562	10/1/2007	Redwood 138/69	transformer		138	69		upgrade?	MI			Planned	$2,022,328	Y		A
A	East	WPSC	1465	2563	10/1/2007	G418, 69 kV line upgrades			69			69 kV line upgrades	MI			Planned	$1,080,000	Y		A
A	West	XEL	56	301	12/31/2010	Chisago	Lindstrom	1	115		310	New 115 kV line	MN	7.0		Planned	$10,100,000			A
A	West	XEL	56	303	12/31/2010	Lawrence Creek	St Croix Falls	1	161		371	New 161 kV line	MN		2.1	Planned	$9,080,000			A
A	West	XEL	56	304	12/31/2010	Lawrence Creek 161-115 kV	transformer	1	161	115	336	New substation with 161-115 kV transformer	MN			Planned	$6,000,000			A
A	West	XEL	56	306	12/31/2010	Lindstrom	Shafer	1	115		310	New line	MN	2.8		Planned	$5,800,000			A
A	West	XEL	56	310	12/31/2010	Shafer	Lawrence Creek	1	115		310	New line	MN	6.2		Planned	$3,500,000			A
A	West	XEL	56	1088	12/31/2010	Lawrence Creek 115-69 kV	transformer	1	115	69	70		MN			Planned	$1,631,000			A
A	West	XEL	270	1138	6/1/2008	Champlin	Champlin Tap	1	115		310	Upgrade existing line	MN	2.4		Planned	$382,923			A
A	West	XEL	385	311	7/1/2007	Split Rock	Nobles Co	1	345		2085	New line	MN		52.0	Planned	$44,966,947			A
A	West	XEL	385	537	8/1/2007	Buffalo Ridge	Yankee	1	115		620	New 115 kV line	MN			Planned				A
A	West	XEL	385	302	9/1/2007	Fenton	Chanarambie	1	115		600	New 115 kV line	MN		14.0	Planned	$7,412,393			A
A	West	XEL	385	308	10/1/2007	Nobles Co	Fenton	1	115		600	New line	MN		12.0	Planned	$7,913,905			A
A	West	XEL	385	307	11/1/2007	Nobles Co	Lakefield Jct	1	345		2085	New line	MN		42.0	Planned	$37,070,397			A
A	West	XEL	385	309	11/1/2007	Nobles Co 345-115 kV	transformer	1	345	115	600	New transformer	MN			Planned	$5,792,805			A
A	West	XEL	385	2041	11/1/2007	Nobles Co	Capacitor		115		40 Mvar	New capacitor	MN			Planned	$634,038			A
A	West	XEL	385	2315	12/1/2007	Yankee	Brookings County	1	115		620	New 115 kV line	MN			Planned				A
A	West	XEL	385	2283	6/1/2009	Brookings Co	White	2	345		2085	New 345 kV line	SD/MN			Planned				A
A	West	XEL	385	975	12/31/2009	Nobles Co 345-115 kV	transformer	2	345	115	672	New transformer	MN			Planned	$5,792,805			A
A	West	XEL	385	272	1/1/2010	Redwood Falls Tap	Franklin	1	115		310	Upgrade existing 115 kV line	MN	13.0		Planned	$3,185,000			A
A	West	XEL	609	800	12/31/2007	Long Lake	Oakdale (from Woodbury)	1	115		310	Upgrade existing line	MN	3.7		Planned	$760,000			A
A	West	XEL	673	1361	7/1/2008	Champlin Tap	Crooked Lake	1	115		223	Upgrade existing line	MN	3.1		Planned	$310,000			A
A	West	XEL	674	1362	6/1/2008	High Bridge	Rogers Lake	1	115		585	Upgrade existing line	MN	4.2		Planned	$2,400,000			A
A	West	XEL	778	3086	11/1/2007	Nobles Co	Reactor #2		34.5		50 Mvar	New reactor	MN			Planned	$200,000			A
A	West	XEL	780	3088	11/1/2007	Fieldon Township	Series Capacitor		345		20 ohms	New series capacitor on LGS-Wilmarth 345	MN			Planned	$10,100,000			A
A	West	XEL	1031	803	3/1/2008	Kasson	Dodge Center	1	69		84	upgrade line	MN	7.8		Planned	$780,000			A

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App ABC	Region	Reporting Source	PrjID	Facil ID	Expected ISD	From Sub	To Sub or Equipment	Ckt	High kV	Low kV	Ratings	Upgrade Description	State	Miles Upg	Miles New	Planning Status	Estimated Cost	C.S.	P.S.	M07 ABC
A	West	XEL	1364	2274	1/30/2007	Lakefield Jct	Lakefield Generation	1	345		918	Raise the structures to increase the thermal rating	MN			Planned				A
A	West	XEL	1365	2275	12/31/2007	Edina	Eden Prairie	1	115		310	Reconductor	MN	4.7		Planned	$3,730,000			A
A	West	XEL	1366	2277	5/1/2008	Colvill Generating station	Transformer	1	161	115	187	New sub with transformer relocated from Cannon Falls substation	MN			Planned	$10,428,380	Y		A
A	West	XEL	1366	2278	5/1/2008	Colvill Generating station	Cannon Falls	1	115		140	Build in and out of the Colvill generating station from Cannon Falls - Empire 115 kV line	MN			Planned	$0	Y		A
A	West	XEL	1366	2279	5/1/2008	Colvill Generating station	Cannon Falls	2	115		167	Build in and out of the Covill generating station from Cannon Falls - Spring Creek line	MN			Planned	$0	Y		A
A	West	XEL	1366	2280	5/1/2008	Colvill Generating station	Empire	1	115		200	Build in and out of the Colvill generating station from Cannon Falls - Empire 115 kV line	MN			Planned	$3,150,000	Y		A
A	West	XEL	1366	2281	5/1/2008	Colvill Generating station	Spring Creek	1	161		234	Build in and out of the Covill generating station from Cannon Falls - Spring Creek line	MN			Planned	$365,000	Y		A
A	West	XEL	1456	2490	11/1/2007	Yankee	feeders		34.5			50 MW 34.5 kV feeder and all associated equipment breaker positions owned by NSP	MN			Planned	$531,600			A
A	West	XEL	1456	2491	11/1/2007	Yankee	transformer		118	36.2	120 MVA	a new 120 MVA, 118-36.2 kV transformer, a 115 kV breaker, switches, and 34.5 kV breakers and switches and all other associated equipment.	MN			Planned	$2,826,000	Y		A
A	West	XEL	1457	2303	12/31/2009	Nobles County	Fenton	2	115		620	New 115 kV line plus permitting and ROW	MN			Planned	$13,560,000	Y		A
A	West	XEL	1457	2494	12/31/2009	Nobles	feeders		34.5			four new 50 MW 34.5 kV feeders and all associated equipment at Nobles County Sub.	MN			Planned	$1,100,000			A
A	West	XEL	1457	2550	12/31/2009	Nobles County	substation		115			Substation upgrades	MN			Planned	$11,992,730	Y		A
A	West	XEL	1457	2552	12/31/2009	Fenton County	substation		115			Substation upgrades	MN			Planned	$776,000	Y		A
A	West	XEL	1457	2565	12/31/2009	Nobles County	substation		345			345 kV substation upgrades	MN			Planned	$344,270	Y	Y	A
A	West	XEL	1457	2301	12/31/2010	Hazel Creek	Capacitor and SVC		115		53 & 33 Mvar	Capacitor 53 Mvar, SVC 33 Mvar	MN			Planned	$0	Y		A
A	West	XEL	1457	2551	12/31/2010	Hazel Creek	substation		115			New Substation and in-and-out taps to transmission	MN			Planned	$10,962,000	Y		A
A	West	XEL	1458	2299	12/31/2009	Yankee	Brookings County	2	115		620	New 115 kV line plus permitting and ROW	MN			Planned	$9,955,000	Y		A
A	West	XEL	1458	2553	12/31/2009	Yankee	substation		115		120 MVA	Substation upgrades (new 115/34.5 transformer, 8 115 kV CB, 4 -34.5 kV CB)	MN			Planned	$7,120,000	Y		A
A	West	XEL	1458	2554	12/31/2009	Brookings Co	substation	2	345	115	448 MVA	Substation upgrades (new 345/115 transformer, 3 115 kV CB, associated equip)	MN			Planned	$6,101,122	Y		A
A	West	XEL	1458	2566	12/31/2009	Brookings Co	substation		345			Substation upgrades 4-345 kV CB	MN			Planned	$1,313,878	Y	Y	A
A	West	XEL	1458	2549	12/31/2010	Hazel Creek	Capacitor and SVC		115		53 & 33 Mvar	Capacitor 53 Mvar, CB, SVC 33 Mvar	MN			Planned	$5,290,000	Y		A
A	West	XEL	1458	2496	11/30/2011	Yankee	feeders		34.5			four new 50 MW underground feeder lines and all associated equipment	MN			Planned	$2,202,000			A
A	West	XEL	1459	2564	1/1/2009	Dakota County Sub	in-and-out tap		345			tap Blue Lake-Prairie Island 345 kVl ine	MN			Planned	$2,425,500	Y	Y	A
A	West	XEL	1489	2548	6/1/2009	Woodbury	Tanners Lake	1	115		256	Upgrade to 310 MVA	MN		3.5	Planned	$525,000			A
C>A	West	XEL	1613	2653	5/30/2012	Hazel Run Substation			115			20 Mvar SVC	MN			Planned	$4,779,000	Y		A
C>A	West	XEL	1614	2654	5/30/2012	Hazel Crk Substation			115			30 Mvar SVC	MN			Planned	$4,803,000	Y		A
A	West	XEL (NSP)	1454	2484	9/1/2007	Yankee	Transformer		115	34.5	120 MVA	New Transformer, plus 1 115 kv breaker and two 34.5 kV breakers	MN			Planned	$2,306,000			A
A	West	XEL (NSP)	1455	2488	5/1/2009	Riverside Generating Plant	breakers		115			IC to install 115 kV breakers on IC side of intercon	MN			planned	$165,000			A
A	West	XEL (NSP)	1455	2489	5/1/2009	Riverside Generating Plant	Apache Substation		115		63 kA CB	IC to install three new 115 kV, 63 kA interrupting ra	MN			Planned	$2,605,000			A
A	West	XEL/WAPA	385	645	12/1/2007	Brookings Co	White	1	345		600		SD		2.0	Planned				A
A	West	XEL/WAPA	385	646	12/1/2007	Brookings Co	345/115 transformer	1	345	115	672		SD			Planned	$12,179,190			A
A	Central	DEM	853	828	6/1/2015	West Lafayette	Cumberland Ave	1	138		306	13806 reconductor with 954ACSR 100C 604F6352	IN	2.0		Planned	$706,921			A
A	West	ALTW	1344	2211	6/1/2016	Beverly Tap	Beverly	1	161		335	new line	IA		7.9	Proposed	$300,000			A
A	West	ALTW	1344	2212	6/1/2016	Beverly	transformer	1	345	161	335	new substation	IA			Proposed	$4,000,000			A

Appendix A-1: MTEP07 New Appendix A Project Cost Allocations by Pricing Zones

Values shown below are subject to change depending on actual project costs (1)

	East			Central						West								
Proj ID	612	1615_GIP		870	152	852	1263_GIP	1620_GIP		277, 1022	1025_GIP	1617_GIP	1541_GIP	1613_GIP	1614_GIP	1616_GIP		**Total**
Zone	NIPS	NIPS	East Total	AMIL	Ameren	DEM	DEM	CWLP	Central Total	MP/GRE	MP	ATC LLC	ALTW	XEL	XEL	ATC LLC	West Total	
Tot. Shared Cost(2)	5,799,614	1,320,000	7,119,614	5,878,500	13,381,100	7,267,473	3,793,500	3,914,650	34,235,223	22,517,026	38,159,771	5,537,000	130,000	2,389,500	2,401,500	171,500	71,306,297	**112,661,134**
Pricing Zone																		
FE	37,466		37,466				97,687		97,687									**135,153**
HE	1,775		1,775			5,930	4,627		10,558									**12,332**
DEM	171,631	14,213	185,844	201,464		7,238,571	3,122,465		10,562,500									**10,748,345**
VECT	3,460		3,460				9,020		9,020									**12,480**
IPL	8,546		8,546				22,282		22,282									**30,828**
NIPS	5,142,497	1,021,431	6,163,928	202,038		22,972	25,853		250,862									**6,414,790**
METC	262,582		262,582				63,991		63,991									**326,574**
ITC	32,218		32,218				84,003		84,003									**116,221**
ALTW	10,069		10,069				26,254		26,254			1,630,447	130,000				1,760,447	**1,796,771**
CWLD	804		804				2,095		2,095									**2,899**
AMMO	24,181		24,181		13,081,381		63,049		13,144,430			86,099					86,099	**13,254,709**
AMIL	24,745	284,356	309,101	5,474,998	299,719		64,519		5,839,236									**6,148,337**
CWLP	1,197		1,197				3,120	3,914,650	3,917,770									**3,918,967**
SIPC	1,189		1,189				3,100		3,100									**4,290**
ATC	35,190		35,190				91,754		91,754		1,009,806	3,553,338				171,500	4,734,644	**4,861,589**
NSP	27,500		27,500				71,702		71,702	2,704,302	10,574,038	267,116		2,389,500	2,401,500		18,336,456	**18,435,658**
MP	5,826		5,826				15,189		15,189	17,190,085	23,106,108						40,296,193	**40,317,208**
SMMPA	875		875				2,280		2,280									**3,155**
GRE	3,427		3,427				8,935		8,935	66,354	332,141						398,495	**410,857**
OTP	2,445		2,445				6,375		6,375	2,556,286	3,066,766						5,623,052	**5,631,872**
MDU	1,993		1,993				5,196		5,196		70,911						70,911	**78,100**
Total	5,799,614	1,320,000	7,119,614	5,878,500	13,381,100	7,267,473	3,793,500	3,914,650	34,235,223	22,517,026	38,159,771	5,537,000	130,000	2,389,500	2,401,500	171,500	71,306,297	**112,661,134**
Tot Proj Cost with 100% GIP(3)	5,799,614	2,640,000		5,878,500	13,381,100	7,267,473	7,587,000	7,829,300		22,517,026	76,319,541	11,074,000	260,000	4,779,000	4,803,000	343,000		**170,478,554**

Notes:

(1) The allocations shown above are estimates which are based on current estimates of project costs and projected in-service dates.The actual allocations will vary depending on the actual project costs and actual in-service dates.

(2) Tot. Shared Cost reflects the Project cost subject to sharing and allocated to pricing zones. This does not include 50% of the Network Upgrade cost of the GIP projects assgined to the Generators.

(3) Tot Proj Cost with 100% GIP includes the total network upgrade costs of the GIPs including the 50% assigned to the generators

Appendix A-2: Additional RECB Cost Allocation Information

Table A-2.1: MTEP07 Shared Projects - Estimated Annual Charge for Allocated Project Cost (Cumulative)

Values shown below (in $) are subject to change depending on actual project costs, actual In-service Dates, and actual Fixed Charge Rates

Year	Annual Charges (Allocation * FCR)	FE	HE	DEM	VECT	IPL	NIPS	METC	ITC	ALTW	CWLD	AMMO	AMIL	CWLP	SIPC	ATC	NSP	MP	SMMPA	GRE	OTP	MDU	Total
2007	324,300	-	-	2,843	-	-	204,286	-	-	26,000	-	-	56,871	-	-	34,300	-	-	-	-	-	-	324,300
2008	2,659,923	7,493	355	77,462	692	1,709	1,273,193	52,516	6,444	28,014	161	4,836	1,156,820	239	238	41,338	5,500	1,165	175	685	489	399	2,659,923
2009	4,113,417	7,493	1,541	1,525,176	692	1,709	1,277,788	52,516	6,444	28,014	161	4,836	1,156,820	239	238	41,338	5,500	1,165	175	685	489	399	4,113,417
2010	12,075,973	7,493	1,541	1,525,176	692	1,709	1,277,788	52,516	6,444	28,014	161	2,621,112	1,216,764	783,169	238	41,338	546,360	3,439,182	175	13,956	511,746	399	12,075,973
2011	13,942,073	27,031	2,466	2,149,669	2,496	6,166	1,282,958	65,315	23,244	359,354	580	2,650,942	1,229,667	783,793	858	770,357	614,124	3,442,220	631	15,743	513,021	1,438	13,942,073
2012	22,532,227	27,031	2,466	2,149,669	2,496	6,166	1,282,958	65,315	23,244	359,354	580	2,650,942	1,229,667	783,793	858	972,318	3,687,132	8,063,442	631	82,171	1,126,374	15,620	22,532,227
Total	**22,532,227**	**27,031**	**2,466**	**2,149,669**	**2,496**	**6,166**	**1,282,958**	**65,315**	**23,244**	**359,354**	**580**	**2,650,942**	**1,229,667**	**783,793**	**858**	**972,318**	**3,687,132**	**8,063,442**	**631**	**82,171**	**1,126,374**	**15,620**	**22,532,227**

Table A-2.2: MTEP06 and MTEP07 Shared Projects - Estimated Annual Charge for Allocated Project Cost (Cumulative)

Year	Annual Charges (Allocation * FCR)	FE	HE	DEM	VECT	IPL	NIPS	METC	ITC	ALTW	CWLD	AMMO	AMIL	CWLP	SIPC	ATC	NSP	MP	SMMPA	GRE	OTP	MDU	Total
2007	24,733,374	108,380	508,150	2,121,446	4,590,751	51,076	222,125	2,726,721	13,617,940	44,331	1,291	43,204	160,361	2,027	2,139	99,390	331,599	10,483	1,595	31,232	55,682	3,451	24,733,374
2008	40,369,262	1,767,996	512,986	5,540,572	4,599,499	72,957	1,313,443	4,567,061	13,697,584	950,868	3,074	102,320	2,368,319	4,813	5,065	2,961,847	1,762,674	24,819	3,773	39,746	61,660	8,185	40,369,261
2009	138,467,294	4,232,441	597,366	8,440,469	4,749,092	447,521	1,734,188	10,537,222	47,331,462	2,712,566	33,191	1,110,215	3,389,796	52,098	54,970	47,545,588	4,220,485	315,544	40,976	669,824	163,596	88,684	138,467,293
2010	157,385,950	4,233,331	597,412	8,441,281	4,749,175	447,730	1,734,421	10,537,801	47,332,221	2,744,389	33,208	3,731,922	3,450,311	835,055	54,997	47,865,483	10,850,986	5,589,996	40,997	815,238	3,210,490	89,504	157,385,948
2011	178,030,050	4,597,423	989,239	13,690,729	8,567,288	1,437,867	2,093,916	13,047,405	47,703,422	3,168,297	40,147	4,087,373	4,734,834	845,914	99,324	48,923,191	14,117,908	5,645,973	49,506	848,495	3,233,830	107,968	178,030,049
2012	186,620,204	4,597,423	989,239	13,690,729	8,567,288	1,437,867	2,093,916	13,047,405	47,703,422	3,168,297	40,147	4,087,373	4,734,834	845,914	99,324	49,125,152	17,190,916	10,267,195	49,506	914,923	3,847,183	122,150	186,620,203
Total	**186,620,204**	**4,597,423**	**989,239**	**13,690,729**	**8,567,288**	**1,437,867**	**2,093,916**	**13,047,405**	**47,703,422**	**3,168,297**	**40,147**	**4,087,373**	**4,734,834**	**845,914**	**99,324**	**49,125,152**	**17,190,916**	**10,267,195**	**49,506**	**914,923**	**3,847,183**	**122,150**	**186,620,203**

Notes:
1. The annual cumalative charges shown above are estimates only which are based on current estimates of project costs, projected in-service dates, and an assumed Fixed Charge Rate of 20%. For the purpose of these estimates, project charges were assumed to begin in the project in-service year. The actual allocations/charges will vary depending on the actual project costs, actual in-service dates, and actual Fixed Charge Rates.
2. Annual charge for allocated projects costs shown above are cumulative revenue requirement.

    Estimated Annual Charge for Allocated Project Cost = Allocated Project Cost x Fixed Charge Rate of Constructing TO

3. Annual charges shown above include charges due to allocations from both own projects and external projects
4. There were no 2012 values in MTEP06 annual charge calculations, therefore, 2012 cumulative values for MTEP06 were assumed same as 2011 values.

MTEP06 shared Rev 03 Notes: This version includes the final cost allocation values for three additional projects in Central area (Proj IDs 1004, 1259, 1257)

Table A-2.3: RECB Cost Allocation of MTEP06 and MTEP07 Shared Appendix A Projects

							Pricing Zone								Pricing Zone								
	FE	HE	DEM	VECT	IPL	NIPS	METC	ITC	ALTW	CWLD	AMMO	AMIL	CWLP	SIPC	ATC	NSP	MP	SMMPA	GRE	OTP	MDU	Total
Total Shared Project Costs(1)	13,994,346		28,748,469	103,100,000		7,119,614	42,313,900	273,950,000	10,130,000		13,381,100	11,143,490	3,914,650		277,390,756	59,212,076	70,527,061		4,317,644	13,857,910		
Project Cost Allocation to Others	(1,566,407)		(1,896,070)	(61,087,430)		(955,686)	(2,872,540)	(41,365,574)	(892,758)		(299,719)	(403,502)			(41,632,917)	(999,875)	(21,049,378)		(1,798,832)	(923,450)		
Project cost Allocation from Others	10,559,172	4,946,197	41,601,246	823,872	7,189,333	4,305,650	25,795,666	5,932,687	6,604,245	200,731	7,355,482	12,934,185	314,924	496,620	9,867,922	27,742,377	1,858,288	247,531	2,055,804	6,301,460	610,749	**177,744,140**
Net Project Cost	22,987,111	4,946,197	68,453,645	42,836,441	7,189,333	10,469,578	65,237,025	238,517,113	15,841,487	200,731	20,436,863	23,674,173	4,229,574	496,620	245,625,761	85,954,577	51,335,971	247,531	4,574,616	19,235,920	610,749	**933,101,016**
Net Transmission Plant in Service per Attachment O - July 2007	643,943,794	86,857,778	849,790,722	119,680,938	122,883,756	418,512,798	306,985,884	673,835,000	407,860,518	6,921,851	376,168,561	406,825,712	23,286,422	26,221,309	1,779,096,830	950,310,181	113,081,488	91,468,130	310,914,425	121,875,699	51,399,639	

Notes:
(1) Total Shared Cost reflects the Project cost subject to sharing and allocated to pricing zones. This does not include 50% of the Network Upgrade cost of the GIP projects assigned to the Generators.

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
B			**Appendix B**											B
B	West	ALTW	1340	Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer (option 2)	Build a new Hazleton - Lore - Salem 345 kV line with a Lore 345/161 kV 335/335 MVA transformer (option 2)	IA				$78,000,000	6/1/2013	345	161	B
B	West	ALTW	1345	Replace the limiting facility of CTs and conductor inside the substations for Quad Cities-Rock Creek-Salem 345 kV line	Replace the limiting facility of CTs and conductor inside the substations for 345 kV line Quad Cities-Rock Creek-Salem so the line rating can be raised to the same as conductor rating between substations	IA					6/1/2011	345		B
B	West	ALTW	1346	Upgrade conductor inside the substation so the ratings of Rock Creek 345/161 kV transformer are 448 MVA limited by transformer	Upgrade conductor inside the substation so the ratings of Rock Creek 345/161 kV transformer are 448 MVA limited by transformer	IA				$100,000	6/1/2011	345	161	B
C>B	West	ALTW	1522	6th Street - Beverly	New line to serve new industrial customer load.	IA				$3,500,000	6/1/2008	161		B
C>B	West	ALTW	1618	Hrn Lk-Lkfld 161kV Ckt 1 Rbld	Rebuild Heron Lake-Lakefield 161kV line, sum rate 446 MVA	MN				$6,800,000	12/31/2008	161		B
C>B	West	ALTW	1619	Grnd Mnd 161-69kV 2nd Xfmr & 161kV loop	Install a 2nd Grand Mound 161-69kV Xfmr (75 MVA) & build a 2.0 miles of new line from the Grand Mound sub to tap the E. Calamus-Maquoketa line (approx. 87% from Maq-E.Cal). The E. Calamus-new tap portion of line will be retired. Existing E.Cal-Maq bkr will feed to GMnd and a new GMnd bkr will feed to Maq. The three terminal line at E.Calamus will be	IA				$2,407,708	12/31/2008	161	69	B
A>B	Central	Ameren	717	Conway-Tyson-3 138 kV	Conway-Orchard Gardens section of Conway-Tyson-3 138 kV - Increase ground clearance	MO		Other	Excluded	$125,350	6/1/2010	138		B
A>B	Central	Ameren	718	Conway-Tyson-4 138 kV	Conway-Orchard Gardens section of Conway-Tyson-4 138 kV - Increase ground clearance	MO		Other	Excluded	$125,350	6/1/2010	138		B
A>B	Central	Ameren	720	Page 138/34 kV Substation	Page 138/34 kV Substation - Replace 3-138 kV Breakers	MO		Other	Excluded	$587,500	12/1/2008	138		B
B	Central	Ameren	721	Wildwood 345/138 kV Substation	Wildwood 345/138 kV Substation - Add 2-345 kV Breakers	MO				$2,095,300	6/1/2009	345		B
B	Central	Ameren	1233	Cahokia-Ashley-2 138 kV	Replace bus conductor and retap CTs	MO				$116,300	6/1/2009	138		B
C>B	Central	Ameren	1235	Fredericktown-AECI Fredericktown	Increase ground clearance on 12 miles	MO				$970,500	6/1/2009	161		B
B	Central	Ameren	1523	Coffeen-Pana, North-Upgrade Terminal Equipment	Replace terminal equipment at Coffeen and Pana, North terminals	IL				$572,000	6/1/2007	345		B
B	Central	AmerenCILCO	874	East Springfield 138/69 kV Substation	East Springfield 138/69 kV Substation - Replace terminal equipment	IL				$344,300	6/1/2010	138		B
B	Central	AmerenIP	734	Washington Street Substation Development	Washington Street Sub - Reconductor from S. Bloomington Substation to Tower 512	IL				$575,400	6/1/2009	138		B
B	Central	AmerenIP	1234	Havana, South-Mason City, West 138 kV	Increase ground clearance on 18.4 miles	IL				$642,300	6/1/2009	138		B
B	Central	AmerenIP	1236	Stallings-Prairie State Plant 345 kV	Replace 2000 A terminal equipment with 3000 A equipment	IL					6/1/2011	345		B
B	Central	AmerenIP	1239	Normal, East-Brokaw 138 kV	Replace 600 A terminal equipment at Normal, East Sub. With 1200 A	IL					6/1/2010	138		B
B	Central	AmerenIP	1351	Pana North - Decatur Rt. 51 L1462	Pana North - Decatur Rt. 51 L1462					$266,300	6/1/2008	138		B
B	Central	AmerenIP	1524	Porter Road-East Belleville - Upgrade Terminal Equipment	Replace terminal equipment at Porter Road Substation	IL				$24,000	6/1/2007	138		B
B	Central	AmerenIP	1526	N. Staunton-Midway - Upgrade Terminal Equipment	Replace terminal equipment at N. Staunton	IL				$375,100	6/1/2008	138		B

Project Information from Facility Table

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
B	Central	AmerenIP	1528	Rising Substation - Increase Xfmr Rating	Increase rating of existing 345/138 kV 450 MVA Transformer	IL				$171,600	6/1/2009	345	138	B
B	Central	AmerenIP	1531	S. Bloomington-Clinton Rt. 54 - Upgrade Terminal Equipment	Replace terminal equipment at S. Bloomington	IL					6/1/2010	138		B
B	Central	AmerenIP	1532	Stallings-E. Collinsville - Upgrade Terminal Equipment, Increase Ground Clearance	Replace terminal equipment at Stallings, increase ground clearance between Stallings, Maryville REA	IL				$744,800	6/1/2010	138		B
B	Central	AmerenIP	1533	Washington Street-S. Bloomington - Upgrade Terminal Equipment	Replace terminal equipment at S. Bloomington	IL				$39,400	6/1/2010	138		B
B	Central	AmerenIP	1534	W. Mt. Vernon-Xenia - Upgrade Terminal Equipment	Replace terminal equipment at W. Mt. Vernon	IL				$2,069,600	6/1/2010	345		B
B	Central	AmerenIP	1535	Wood River-Stallings	Replace terminal equipment at Stallings, reconductor portion of line	IL					6/1/2010	138		B
B	Central	AmerenIP	1537	Mt. Vernon, West-S. Centralia - Upgrade Terminal Equipment	Replace terminal equipment at S. Centralia	IL					6/1/2011	138		B
C>B	West	ATC LLC	174	Canal-Dunn Road 138 kV	Canal - Dunn Road 138 ckt , Sum rate 400	WI				$4,200,000	6/1/2012	138		B
A>B	West	ATC LLC	333	Hiawatha-Indian Lake conversion to 138 kV and Hiawatha-Pine River-Mackinac conversion to 138 kV	Construct Mackinac 138 kV substation (new Straits substation)	WI		Other	Excluded	$6,200,000	5/1/2009	138		B
B	West	ATC LLC	356	Rockdale-West Middleton 345 kV	Construct 345 kV line from Rockdale to West Middleton, Construct a 345 kV bus and install a 345/138 kV 500 MVA transformer at West Middleton, Expand Rockdale 345 kV substation	WI				$72,644,254	6/1/2013	345	138	B
B	West	ATC LLC	544	Bluemound 200 MVAR capacitor bank	Bluemound 200 MVAR capacitors	WI				$3,300,000	6/1/2010	138		B
C>B	West	ATC LLC	574	Monroe County - Council Creek 161 kV line projects	Monroe County - Council Creek 161 kV line, Council Creek 161/138 kV transformer; Petenwell-Saratoga 138 kV rebuild and Council Creek-Petenwell uprate 138 kV	WI				$34,200,000	6/1/2012	161	138	B
B	West	ATC LLC	682	Huiskamp-Blount 138 kV line	Convert Huiskamp-Blount 69 kV line to 138 kV	WI				$20,000,000	6/1/2012	138		B
B	West	ATC LLC	884	Spring Green 32 MVAR capacitor bank	Spring Green 32 MVAR capacitor bank	WI				$1,200,000	6/1/2010	69		B
B	West	ATC LLC	887	Bain 345 kV bus	Bain 345 kV bus	WI				$2,100,000	6/1/2011	345		B
B	West	ATC LLC	888	Plains second 345/138 kV transformer	Plains second 345/138 kV transformer	MI				$5,400,000	6/1/2009	345	138	B
B	West	ATC LLC	889	Brule substation relocation	Brule (renamed Aspen) substation relocation	MI				$5,700,000	10/1/2007	69		B
B	West	ATC LLC	1268	Cap banks at Artesian and Kilbourn	Install 2-16.33 MVAR 69 kV capacitor banks at Kilbourn and install 2-24.5 MVAR 138-kV capacitor banks at Artesian	WI					6/1/2009			B
B	West	ATC LLC	1269	Arcadian transformer replacement	Replace Arcadian 345/138kV transformer #3 with a 500MVA transformer.	WI				$3,500,000	6/1/2013	345	138	B
B	West	ATC LLC	1270	Upgrade Arcadian - Waukesha 138kV lines	Increase clearances of the two Arcadian - Waukesha 138kV lines	WI				$800,000	6/1/2011	138		B
B	West	ATC LLC	1279	North Beaver Dam 49 MVAR cap bank	install two 24.5 MVAR cap bank at North Beaver Dam	WI				$1,800,000	6/1/2009	138		B
B	West	ATC LLC	1280	South Lake Geneva 2nd cap bank	install 2nd 16.33 MVAR cap banks at South Lake Geneva	WI				$1,500,000	6/1/2010	69		B

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
B	West	ATC LLC	1282	Add two 5.4 Mvar 69 kV Capacitor banks at the Osceola substation in Houghton County, MI	Add two 5.4 Mvar 69 kV Capacitor banks at the Osceola substation in Houghton County, MI	MI					6/1/2008	69		B
B	West	ATC LLC	1284	Tie the 138kV radial line Racine - Somers - Albers to the 138kV substation at Albers. Also upgrade the 138kV radial line to 345/477 summer normal/emergency ratings.	Tie the 138kV radial line Racine - Somers - Albers to the 138kV substation at Albers. Also upgrade the 138kV radial line to 345/477 summer normal/emergency ratings.	WI				$4,181,904	6/1/2011	138		B
B	West	ATC LLC	1353	Hiawatha - Pine River 69	Hiawatha - Pine River 69 kV maintenance rebuild to 138kV standards	WI					12/31/2009	69		B
C>B	West	ATC LLC	1553	Hiawatha 138kV Capacitor Bank	Install one 16.33 MVAR 138kV capacitor bank at Hiawatha substation	MI				$615,283	6/1/2009	138		B
C>B	West	ATC LLC	1554	Indian Lake 138kV Capacitor Bank	Install one 16.33 MVAR 138kV capacitor bank at Indian Lake substation	MI				$584,007	6/1/2010	138		B
C>B	West	ATC LLC	1622	Uprate Oak Creek-St Rita 138-kV	Increase clearance of the Oak Creek-St Rita 138-kV line	WI					6/1/2013	138		B
C>B	Central	CWLP	1552	Loop Holland to East Springfield 138 kV line through CWLP Interstate substation	Loop Holland to East Springfield 138 kV line through CWLP Interstate substation (Two New Tie Lines)	IL				$1,500,000	10/1/2009	138		B
B	Central	DEI	1556	Wheatland to Whitestown 345	New 345 kV line from Wheatland to Whitestown	IN				$113,000,000	5/1/2011	345		B
B	Central	DEI	1557	Wheatland to Bloomington to Pritchard to Franklin to Hanna 345	Wheatland to Bloomington to Pritchard to Franklin to Hanna 345	IN				$95,140,000	5/1/2011	345		B
B	Central	DEI	1558	Close Wheatland Breaker	Close the breaker at IPL's Wheatland - make upgrade to Petersburg - Francisco and the Petersburg - Thompson 345 kV to address 1st contingency limitations	IN				$11,435,000	5/1/2011	345		B
B	Central	DEM	1264	Speed	Replace existing 345/138 transformer at Speed with a new transformer rated at 3,000A or higher.	IN				$5,000,000	6/1/2011	345	138	B
B	Central	DEM	1504	Honda	New substation for Honda in Greensburg taps the Duke Energy 138kV line between Greensburg and Shelbyville Northeast.	IN				$0	12/1/2007	138		B
B	Central	DEM	1505	HE Owensville North 138/69	Loop Gibson to Princeton 13863 line through new HE Owensville North 138/69 substation.	IN				$0	12/31/2007	138		B
B	Central	DEM	1507	Vectren Francisco 345/138	Loop 34516 line through new Vectren Francisco 345/138kV substation. Reroute Duke Energy 138kV around substation.	IN				$0	7/9/2007	345		B
B	Central	DEM	1510	Wabash River to TH Water St 138 100C Uprate	Uprate 138kV from Wabash River to Terre Haute Water St to 100C.	IN				$120,282	6/1/2008	138		B
B	Central	DEM	1514	Wabash River to Staunton 230 100C Uprate	Uprate Wabash River to Staunton 23002 to 100C summer operating temperature and 80C winter (559MVA).	IN					6/1/2009	230		B
C>B	Central	DEM	1515	Speed relays for LGEE Trimble	Replace Speed relays for the LGEE Trimble addition	IN				$0	10/1/2009	345		B
B	Central	DEM	1563	Todhunter to AK Steel 138kv reconductor	Replace existing conductor with 954ACSR @ 100C from Todhunter to AK Steel due to new load addition.	OH				$300,000	12/31/2007	138		B
C>B	Central	DEM	1566	Rockies Express to AK Steel 138KV reconductor of F5682	Replace F5682 existing conductor with 954ACSR @ 100C from new Rockies Express (REX) substation to AK Steel.	OH				$600,000	10/15/2008	138		B

Project Information from Facility Table

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
C>B	Central	DEM	1568	Qualitech 345/138KV Transformer and breakers	Qualitech Sub- Install one 345/138kv, 300Mva Xtr and 2-345kv Bkrs and 1-138kv Bkr to provide second 138kv source to proposed Hendricks Co 138kv system	IN				$4,561,674	6/1/2009	345	138	B
C>B	Central	DEM	1569	Qualitech to Pittsboro new 138kv line	Construct new 138kv line, Qualitech to Pittsboro, and connect to the Pittsboro-Brownsbg line to provide new 954ACSR outlet line from Qualitech 345/138kV Bank	IN				$1,507,856	6/1/2009	138		B
C>B	Central	DEM	1570	Plainfield South to Pittsboro 69KV to 138KV Conversion	Convert the existing 69KV (69144) line from Plainfield S. to Pittsboro (and 4 distribution subs) over to 138KV operation and connect to the new Qualitech to Pittsboro 138KV line	IN				$4,139,000	6/1/2009	138		B
B	East	FE	1324	Reconductor Walbridge Jct.-Maclean	Increaes conductor size from 636 ACSR 26/7, possibly with 477 ACSS/TW conductors	OH				$247,900	6/1/2009	138		B
B	East	FE	1339	Maysville Substation - Add 138 kV Capacitor Bk.	Add 1 - 50 MVAR Cap Bank with 1 - 138 kV Breaker	OH				$451,700	6/1/2010	138		B
C>B	East	FE	1598	Midway-Richland-Wauseon and Midway-Richland-Stryker 138kV eliminate two 3 terminal lines	Midway-Richland-Wauseon and Midway-Richland-Stryker 138kV eliminate two 3 terminal lines. No system reinforcements are required.	OH				$68,500	12/1/2008	138		B
C>B	East	FE	1599	Bayshore-Maclean-Lemoyne 138kV 3-terminal lines elimination	Bayshore-Maclean-Lemoyne 138kV eliminate two 3-terminal lines and reconductor the Walbridge Jct.-Maclean 13202 line segment from 636 ACSR 26/7 to 477 ACSS/TW conductors. Also, in the Lemoyne line terminal replace the 800 amp wave trap with a 1600 amp wave trap.	OH				$1,020,100	6/1/2009	138		B
C>B	East	FE	1605	Brim-Lemoyne-Midway 138kV 3-terminal line elimination	Eliminate Brim-Lemoyne-Midway 138kV 3-terminal line by creating Brim-Midway and Brim-Lemoyne 138kV 2-terminal lines. Loop Lemoyne-Midway #2 ckt into Brim. Install two 138kV breakers and a 138kV circuit switcher at Brim.	OH				$800,000	12/1/2011	138		B
C>B	East	FE	1608	SE Ashtabula Sub 345kV Loop Expansion	Establish 345kV ring bus, add a new 345/138 xfmr with its own position at Ashtabula	OH				$10,468,849	6/1/2010	345	138	B
C>B	East	FE	1611	TX Avon-Fox 345kV Transmission Line	Add new 345kV Transmission Line between Avon and Fox in CEI.	OH				$19,500,000	6/1/2012	345		B
C>B	East	FE	1612	Cranberry 500/138kV Sub	Construct a 500/138kV Sub with four exits in the Cranberry/Adams Township area.	PA				$16,568,983	6/1/2010	500	138	B
B	West	GRE	602	Brownton - McLeod 115 kV line	Brownton - McLeod 115 kV line	MN				$4,675,000	6/1/2012	115		B
B	West	GRE/MPC/XEL	286	Fargo, ND – St Cloud/Monticello, MN area 345 kV project	AlexandriaSS - Waite Park - Monticello 345 ckt 1, Sum rate 2085	MN		Other (>BRP)	TBD	$149,910,000	7/1/2012	345	115	B
B	West	GRE/MPC/XEL	287	Fargo, ND – St Cloud/Monticello, MN area 345 kV project	Maple River - AlexandriaSS 345 ckt 1, Sum rate 2085	MN	ND	Other (>BRP)	TBD	$117,448,000	7/1/2012	345		B
B	West	GRE/XEL	603	Alexandria - West St. Cloud 115 kV line	Alexandria - West St. Cloud 115 kV line	MN				$36,954,688	6/1/2012	115		B
C>B	Central	HE	1635	Ramsay Primary Substation Ringbus	345kV Ringbus Addition/Modification to Ramsay Primary	IN				$5,000,000	6/1/2009	345		B
C>B	Central	IPL	897	Thompson 345/138kV Autotransformer	Add new 345/138kV autotransformer at Thompson Substation	IN				$4,500,000	6/1/2012	345	138	B
B	Central	IPL	1634	Pete-Vincennes Line Capacity Upgrade	Increase Capacity By Changing CT Ratio At Petersburg To 1200A	IN				$2,500	6/1/2008	138		B

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
B	West	MDU	1479	Cabin Creek: Switchyard & 115/69 kV transformer	Cabin Creek: Switchyard & 115/69 kV transformer	ND					11/1/2007	115	60	B
B	East	METC	1436	Mullins	Install a second distribution transformer served from Four Mile-Wealthy line	MI				$56,000	5/1/2008	138	12.5	B
B	West	MP	1292	Raise tower height on ETCO-Forbes 115 kV line	Raise tower height on ETCO-Forbes 115 kV line so the 336 ACSR conductor rating can reach 122/134 MVA	MN				$400,000	6/1/2011	115		B
B	East	NIPS	919	Lagrange - Increase #1 138-69KV Transformer Capacity to 168 MVA	Replace Lagrange #1 138/69 kV 112 MVA transformer with a 168 MVA transformer.	IN				$1,593,300	12/1/2008	138	69	B
B	East	NIPS	923	Plymouth - Add 3rd 138-69KV 168 MVA Transformer	Install a 3rd 138/69 KV 168 MVA transformer, associated breakers and bus at Plymouth to increase station capacity.	IN				$2,689,400	5/1/2007	138	69	B
B	West	OTP	549	Jamestown Reactor Addition	Jamestown 115 kV 25 MVAR reactor	ND				$436,672	1/1/2008	115		B
B	West	OTP	973	Big Stone II Generation Project	Build New Big Stone - Ortonville 230 kV Line, Convert Ortonville - Johnson Jct. 115 kV line to 230 kV, Convert Johnson Jct. - Morris 115 kV Line to 230 kV, Install a new Johnson Jct. 230/115 kV Transformer, Replace existing Morris 230/115 kV Transforme, Build New Big Stone - Canby 230 kV Line, Convert existing Canby - Granite Falls 115 kV Line to 230 kV, Install a new Canby 230/115 kV Transformer, Upgrade existing Big Stone - Browns Valley 230 kV Line	MN	SD			$114,750,000	11/1/2012	230	115	B
B	West	OTP/MPC	971	Winger 230/115 kV Transformer Upgrade	Winger 230/115 kV Transformer upgrade	MN				$3,715,351	12/31/2010	230	115	B
B	Central	Vectren (SIGE)	1002	New Northeast to Oak Grove to Culley Line 138 kV	New Northeast to Oak Grove to Culley Line 138 kV	IN				$8,500,000	5/31/2009	138		B
B	Central	Vectren (SIGE)	1023	Scott Township 138/69 kV substation and Scott Township - Elliott 138 kV line	New Scott Township 138/69 kV substation and new 138 kV line from Scott Township to Elliott	IN				$13,900,000	5/31/2009	138	69	B
C>B	East	WPSC	1209	Hersey 69KV Ring Bus	Convert 6 breaker bus at Hersey to Ring Bus	MI				$2,300,000	8/1/2007	69		B
C>B	East	WPSC	1210	Lewiston II Breaker Station	Add a 69KV breaker in the line from Atlanta to Gaylord	MI				$520,000	8/1/2007	69		B
B	East	WPSC	1211	Grand Traverse - Grawn Line Rebuild	Line Rebuild to 795ACSR for future 138KV operation	MI				$1,200,000	8/1/2007	69		B
C>B	East	WPSC	1213	Vestaburg Capacitor Bank	Add 6MVAR Capacitor Bank at Vestaburg Substation	MI				$3,000	8/1/2007	69		B
C>B	East	WPSC	1217	Grawn 69KV Ring Bus	Convert 4 breaker bus at Grawn to Ring Bus	MI				$1,900,000	8/1/2008	69		B
C>B	East	WPSC	1218	Atlanta 69KV Ring Bus	Convert 4 breaker bus at Atlanta to Ring Bus	MI				$1,900,000	8/1/2009	69		B
C>B	East	WPSC	1219	Lake County - Star Lake Line Rebuild	Line Rebuild to 795ACSR for future 138KV operation	MI				$1,800,000	8/1/2009	69		B
B	East	WPSC	1221	Redwood - New Era Line Rebuild	Line Rebuild to 795ACSR for future 138KV operation	MI				$1,500,000	8/1/2010	69		B
C>B	East	WPSC	1222	Lake County 69kV Ring Bus	Convert 4 breaker bus at Lake County to Ring Bus	MI				$3,800,000	8/1/2010	69		B
B	East	WPSC	1274	Allendale to Blendon Line Re-rate	Rerate the line from Allendale Sub to Blendon Sub for an operating temperature of 75C	MI				$150,000	10/1/2007	69		B
B	East	WPSC	1275	Boyne City to Wilson Line Re-Rate	Rerate the line from Boyne City Sub to Wilson Sub for an operating temperature of 75C	MI				$200,000	10/1/2007	69		B
B	East	WPSC	1276	Burnips to Goodwin Line Re-Rate	Rerate the line from Burnips Sub to Goodwin Sub for an operating temperature of 75C	MI				$900,000	10/1/2010	69		B

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Project Information from Facility Table

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
B	East	WPSC	1277	Wayland to Goodwin Line Re-Rate	Rerate the line from Wayland Sub to Goodwin Sub for an operating temperature of 75C	MI				$350,000	10/1/2011	69		B
B	East	WPSC	1278	North Shade 6MVAR Cap Bank	Add 6MVAR capacitor bank to North Shade substation	MI				$150,000	10/1/2007	69		B
B	East	WPSC	1299	Lake County 168MVA Transformer	Replace 75MVA Transformer with 168MVA Transformer at Lake County Substation.	MI				$2,600,000	8/1/2011	69		B
B	East	WPSC	1311	Copemish - Karlin line rerate	Rerate line to 75C	MI				$1,400,000	8/1/2011	69		B
B	East	WPSC	1312	Grawn - Karlin line rerate	Rerate line to 75C	MI				$650,000	8/2/2011	69		B
B	East	WPSC	1313	Baldwin - Plains X line rerate	Rerate line to 75C	MI				$700,000	8/3/2011	69		B
B	East	WPSC	1314	Plains X - Star Lake line rerate	Rerate line to 75C	MI				$700,000	8/4/2011	69		B
B	East	WPSC	1315	Potter - Grand Traverse line rerate	Rerate line to 75C	MI				$225,000	8/5/2011	69		B
C>B	East	WPSC	1574	Wayland to Wayland Distribution	Rerate Overloaded Line	MI				$50,000	7/1/2013	69		B
C>B	East	WPSC	1575	Portland Cap Bank	Add 18MVAR Cap bank at Portland	MI				$750,000	7/1/2009	69		B
C>B	East	WPSC	1576	Chester Cap Bank	Add 12MVAR Cap bank at Chester	MI				$750,000	7/1/2009	69		B
C>B	East	WPSC	1577	Copemish to Bretheren	Rerate Overloaded Line	MI				$1,621,500	7/1/2008	69		B
C>B	East	WPSC	1578	Garfield X to Hall Street	Rerate Overloaded Line	MI				$559,500	7/1/2008	69		B
C>B	East	WPSC	1579	Garfield X to Grawn	Rebuild Overloaded Line	MI				$1,152,000	7/1/2008	69		B
C>B	East	WPSC	1580	Redwood to Hart	Rerate Overloaded Line	MI				$265,500	7/1/2013	69		B
C>B	East	WPSC	1581	East Jordan X to Graves X	Rerate Overloaded Line	MI				$1,071,000	7/1/2011	69		B
C>B	East	WPSC	1582	Alba to Graves Junction	Rerate Overloaded Line	MI				$708,000	7/1/2013	69		B
C>B	East	WPSC	1583	Bretheren to Bass Lake	Rerate Overloaded Line	MI				$2,716,500	7/1/2008	69		B
C>B	East	WPSC	1584	Shelby to New Era	Rerate Overloaded Line	MI				$631,500	7/1/2013	69		B
C>B	East	WPSC	1585	Bagley X to Gaylord Distribution	Rerate Overloaded Line	MI				$498,000	7/1/2009	69		B
C>B	East	WPSC	1586	Gaylord to Advance to Oden Rebuild 69kV	Rebuild Overloaded line	MI				$8,633,000	8/1/2010	69		B
C>B	East	WPSC	1588	Casnovia Capacitor Bank	Add 6MVAR capacitor bank to Casnovia	MI				$750,000	8/1/2013	69		B
C>B	West	XEL	675	Rebuild Westgate to Scott County 69 kV to 115 kV	Upgrade 20.1 miles Westgate-Deephaven-Excelsior-Scott County 69kV to 115 kV using 795 ACSS conductor, Upgrade 2 miles Westgate-Eden Prairie 115kV #1 and #2 to 400MVA (PrjID 606), Substation work at Deephaven, Excelsior and Scott County.	MN					6/1/2011	115		B
B	West	XEL	751	Nobles Co 34.5 kV -50 MVAR Reactor #1	Nobles Co 34.5 kV -50 MVAR Reactor #1	MN				$200,000	12/1/2007	34.5		B
B	West	XEL	1285	Build 18 miles 115 kV line from Glencoe - West Waconia	Build 18 miles 115 kV line from Glencoe - West Waconia	MN					6/1/2011	115		B
B	West	XEL	1297	Reconductor Monticello - Oakwood - Hassan 115 kV line	Reconductor Monticello - Oakwood - Hassan 115 kV line with 795 ACSS	MN					6/1/2011	115		B
C>B	West	XEL	1370	Convert/Relocate the 69 kV Rush River substation to existing 161 kV line from Pine Lake - Crystal Cave	Convert/Relocate the 69 kV Rush River substation to existing 161 kV line from Pine Lake - Crystal Cave	WI					5/1/2009	161		B
C>B	West	XEL	1371	Black Dog - Wilson 115 kV #1 Reconductor	Black Dog - Wilson 115 kV #1 Reconductor	MN				$900,000	6/1/2009	115		B
C>B	West	XEL	1373	Ft. Ridgeley - Searles Jct 115 new line and Searles Jct - New Ulm 69 Reconductor	Ft. Ridgeley - Searles Jct 115 new line and Searles Jct - New Ulm 69 Reconductor	MN					6/1/2010	115		B

Project Information from Facility Table

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C>B	West	XEL	1375	BRIGO - Buffalo Ridge Incremental Generation Outlet	BRIGO (non-GIA): Hazle Creek - Minnesota Valley 115 kV line (new), Lake Yankton - SE Marshall 115 kV line, Winnebago Jct 161 capacitor, McLeod 115 capacitor	MN				$10,000,000	6/1/2010	115		B
C>B	West	XEL	1546	Dean Lake - Hyland Lake Upgrade	Upgrade 115 kV line from Dean Lake - Hyland Lake 115 kV line	MN				$1,057,000	6/1/2008	115		B
B	West	XEL/GRE	1203	Brookings, SD – SE Twin Cities 345 kV project	Brookings County -Lyon County-Franklin (Double Crt) -Helena-Lk Marion-Hampton Corner 9 (Single Crt) 345 kV; Hazel - Lyon County 345 kV line	MN	SD	Other (>???)	TBD	$265,680,000	6/1/2011	345	69	B
C>B	West	XEL/GRE	1545	Mankato 115 kV loop	(1) New South Bend 161/115/69 kV susstation. (2) Operate 161 kV line from Wilmarth - South Bend at 115 kV. (3) Convert the 69 kV line from South Bend - Hungry Hollow to 115 kV. (4) Convert the existng line from Hungry Hollow - Pohl tap - Pohl - Eastwood to 115 kV. (5) Convert Pohl Substation to 115 kV. (6) Add 115/69 kV Transformer at Hungry Hollow Substation.	MN				$12,915,000	12/1/2009	115		B
Projects with In Service Dates after Plan Year											1/1/2014			B
C>B	West	ATC LLC	1624	Uprate X-67 Portage-Trienda 138 kv line	Increase clearance and uprate SS equipment	WI					6/1/2014	138		B
B	West	ATC LLC	434	Butternut 28.8 MVAR capacitor bank	Butternut 138, 28.8 MVAR Capacitor bank	WI				$1,050,000	6/1/2015	138		B
B	West	XEL/DPC/RPU	1024	SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV project	Construct Hampton Corner-North Rochester-Belvidere-North LaCrosse 345 kV line, North Rochester - N. Hills 161 kV line, North Rochester-Chester 161 kV line, Hampton Corner 345/161 transformer, North Rochester 354/161 transformer, North LaCrosse 345/161 transformer	MN	WI	Other (>BRP)	TBD	$300,812,400	12/15/2015	345	161	B
B	West	ATC LLC	569	White River T-D interconnection	South Lake Geneva - White River 138 kV line	WI				$4,473,000	6/1/2016	138	69	B
B	West	ATC LLC	573	North Madison-West Middleton 345 kV	North Madison - West Middleton 345 kV line	WI				$46,700,000	6/1/2016	345		B
B	Central	DEM	1521	Bloomington 13836 Switches	Replace the Bloomington 13836 600A breaker disconnect switches with 2000A switches. New limit 800A Wave Trap.	IN				$233,455	6/1/2016	138		B
B	West	OTP	585	Pelican Rapids 115 kV Line Uprate	Pelican Rapids - Pelican Rapids Turkey Plant 115 kV line	MN				$858,869	6/1/2017	115		B
B	West	ATC LLC	89	Mill Road 345/138 kV substation and transformer	Mill Road transformer - 345/138 ckt , Sum rate 500	WI				$29,200,000	6/1/2018	345	138	B
B	West	ATC LLC	341	Rockdale-Mill Road 345 kV line projects	Construct Rockdale-Concord 345 kV line in parallel with existing 138 kV on existing double-width right-of-way. Construct a 345 kV bus and install a 345/138 kV, 500 MVA transformer at Concord. Convert Bark River-Mill Road 138 kV line to 345 kV. Construct a Concord-Bark River 345 kV line. Construct a 345 kV bus and install a 345/138 kV, 500 MVA transformer at Bark River	WI				$94,600,000	6/1/2018	345	138	B
B	Central	AmerenIP	1232	Tap to Tilden-Fayetteville L1526	Tap to Tilden-Fayetteville L1526 for construction power for Prairie State	IL								B
B	Central	AmerenIP	1527	Pana-IP Route 51 - Upgrade Terminal Equipment	Replace terminal equipment at Pana	IL				$250,000		138		B

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App ABC	Region	Reporting Source	PrjID	Facil ID	Expected ISD	From Sub	To Sub or Equipment	Ckt	High kV	Low kV	Ratings	Upgrade Description	State	Miles Upg	Miles New	Planning Status	Estimated Cost	C.S.	P.S.	M07 ABC
B		**Appendix B**																		B
B	West	ALTW	1340	2205	6/1/2013	Lore	transformer	1	345	161	335	new transformer	IA			Proposed	$4,000,000			B
B	West	ALTW	1340	2542	6/1/2013	Salem	Lore	1	345		2000	new line	IA		16.0	Proposed	$16,000,000			B
B	West	ALTW	1340	2543	6/1/2013	Lore	Hazleton	1	345		2000	new line	IA		58.0	Proposed	$58,000,000			B
B	West	ALTW	1345	2546	6/1/2011	Quad Cities	Rock Creek	1	345		1246	upgrade limiting equipment	IA			Proposed				B
B	West	ALTW	1345	2547	6/1/2011	Rock Creek	Salem	1	345		1246	upgrade limiting equipment	IA			Proposed				B
B	West	ALTW	1346	2214	6/1/2011	Rock Creek	transformer	1	345	161	448	upgrade limiting equipment	IA			Proposed	$100,000			B
C>B	West	ALTW	1522	2599	6/1/2008	6th Street	Beverly	1	161		326	new line	IA		5.5	Planned	$3,500,000			B
C>B	West	ALTW	1618	2720	12/31/2008	Heron Lake	Lakefield Jct	1	161		440	Rebuild	MN	17.0		Proposed	$6,800,000			B
C>B	West	ALTW	1619	2721	12/31/2008	Grand Mound 161-69 kV	transformer	2	161	69	74.7 MVA	new Xfmr	IA			Planned	$1,905,500			B
C>B	West	ALTW	1619	2722	12/31/2008	Grand Mound	Maquoketa	1	161		200/200 MVA	New 161kV line	IA		2.0	Planned	$502,208			B
C>B	West	ALTW	1619	2723	12/31/2008	East Calamus	Grand Mound	1	161		200/200 MVA	New 161kV line	IA			Planned				B
C>B	West	ALTW	1619	2724	12/31/2008	East Calamus	Maquoketa	1	161			remove model branch	IA			Planned				B
C>B	West	ALTW	1619	2725	12/31/2008	East Calamus T	Maquoketa	1	161			remove model branch	IA			Planned				B
A>B	Central	Ameren	717	1408	6/1/2010	Conway	Orchard Gardens	1	138		240	increase ground clearance	MO			Proposed	$125,350			B
A>B	Central	Ameren	718	1409	6/1/2010	Conway	Orchard Gardens	2	138		240	increase ground clearance	MO			Proposed	$125,350			B
A>B	Central	Ameren	720	1411	12/1/2008	Page Substation	Replace 3-138 kV Breakers		138			replace existing 138 kV breakers	MO			Proposed	$587,500			B
B	Central	Ameren	721	1412	6/1/2009	Wildwood Sub.	Add 2-345 kV Breakers		345			install new 345 kV breakers	MO			Proposed	$2,095,300			B
B	Central	Ameren	1233	1932	6/1/2009	Cahokia	Ashley	1	138		318	Replace bus conductor and retap CTs at Cahokia t	MO			Proposed	$116,300			B
C>B	Central	Ameren	1235	1934	6/1/2009	Fredericktown	AECI Fredericktown Tap	1	161		250	Increase ground clearance	MO	12.0		Proposed	$970,500			B
B	Central	Ameren	1523	2600	6/1/2007	Coffeen	Pana, North	1	345		1200	Replace terminal equipment at both terminals	IL			Planned	$572,000			B
B	Central	AmerenCILCO	874	852	6/1/2010	East Springfield	Eastdale		138		299	Replace terminal equipment at East Springfield	IL			Proposed	$344,300			B
B	Central	AmerenIP	734	1428	6/1/2009	Washington St. Line 1364	S. Bloomington	1	138		266	reconductor Line 1364 from S. Bloomington to Tow	IL	3.3		Proposed	$575,400			B
B	Central	AmerenIP	1234	1933	6/1/2009	Havana, South	Mason City, West	1	138		155	Increase ground clearance on 18.4 miles	IL	18.4		Proposed	$642,300			B
B	Central	AmerenIP	1236	1935	6/1/2011	Stallings	Prairie State Power Plant	1	345		1297	Replace 2000 A terminal equipment with 3000 A e	IL			Proposed				B
B	Central	AmerenIP	1239	1938	6/1/2010	Normal East	Brokaw	1	138		280	Replace 600 A terminal equipment to 1200 A at No	IL			Proposed				B
B	Central	AmerenIP	1351	1941	6/1/2008	Pana, North	Decatur Rt. 51 L1462	1	138		280	Replace 1200 A terminal equipment with 1600 A e	IL			Planned	$266,300			B
B	Central	AmerenIP	1524	2601	6/1/2007	Porter Road	East Belleville	1	138		214	Replace terminal equipment at Porter Road	IL			Planned	$24,000			B
B	Central	AmerenIP	1526	2603	6/1/2008	Midway	N. Staunton	1	138		280	Replace terminal equipment at N. Staunton	IL			Planned	$375,100			B
B	Central	AmerenIP	1528	2604	6/1/2009	Rising	Transformer	1	345	138	478	Increase rating of existing 450 MVA Transformer	IL			Proposed	$171,600			B
B	Central	AmerenIP	1531	2608	6/1/2010	S. Bloomington	Clinton Rt. 54	1	138		128	Replace terminal equipment at S. Bloomington	IL			Proposed				B
B	Central	AmerenIP	1532	2609	6/1/2010	Stallings	E. Collinsville	1	138		280	Replace terminal equipment at Stallings, increase	IL	4.9		Proposed	$744,800			B
B	Central	AmerenIP	1533	2610	6/1/2010	Washington Street	S. Bloomington	1	138		255	Replace terminal equipment at S. Bloomington	IL			Proposed	$39,400			B
B	Central	AmerenIP	1534	2611	6/1/2010	W. Mt. Vernon	Xenia	1	345		1200	Replace terminal equipment at W. Mt. Vernon	IL			Proposed	$2,069,600			B
B	Central	AmerenIP	1535	2612	6/1/2010	Wood River	Stallings	1	138		259	Replace terminal equipment at Stallings, reconduc	IL	6.0		Proposed				B
B	Central	AmerenIP	1537	2614	6/1/2011	Mt. Vernon, West	S. Centralia	1	138		160	Replace terminal equipment at S. Centralia	IL			Proposed				B
C>B	West	ATC LLC	174	442	6/1/2012	Canal	Dunn Road		138		400 MVA SE		WI		7.6	Planned	$4,200,000			B
A>B	West	ATC LLC	333	891	6/1/2007	Mackinac	Substation relocation		138			Straits substation rename/relocation	MI			Proposed	$5,800,000			B
A>B	West	ATC LLC	333	474	5/1/2009	Hiawatha	Indian Lake (convert double	2	138		279	rebuild in 2006 and convert in 2009	MI	40.0		Proposed	$200,000			B
A>B	West	ATC LLC	333	596	5/1/2009	Hiawatha	Indian Lake (string second 1	2	138		279	string 2nd 138 kV circuit	MI		40.0	Proposed	$200,000			B
B	West	ATC LLC	356	486	6/1/2013	West Middleton	Rockdale	1	345		1200		WI		35.0	Proposed	$63,249,004			B
B	West	ATC LLC	356	488	6/1/2013	West Middleton 345/138	transformer	1	345	138	500		WI			Proposed	$7,888,517			B
B	West	ATC LLC	356	897	6/1/2013	Rockdale	substation expansion		345			expand 345 kV substation	WI			Proposed	$1,506,733			B
B	West	ATC LLC	544	898	6/1/2010	Bluemound	Capacitor bank		138		200 Mvar		WI			Proposed	$3,300,000			B
C>B	West	ATC LLC	574	858	6/1/2012	Council Creek	Petenwell		138			uprate	WI	32.0		Proposed	$200,000			B
C>B	West	ATC LLC	574	1269	6/1/2012	Monroe County (XEL)	Council Creek (ATC)	1	161		530		WI	20.0		Proposed	$16,700,000			B
C>B	West	ATC LLC	574	1370	6/1/2012	Council Creek 161-138 kV	transformer		161	138	280		WI			Proposed	$2,500,000			B
C>B	West	ATC LLC	574	859	6/1/2016	Petenwell	Saratoga		138			rebuild/reconductor	WI	23.0		Proposed	$14,800,000			B
B	West	ATC LLC	682	1372	6/1/2012	Huiskamp	Blount (convert)	1	138		290	convert 69 to 138 kV	WI	5.0		Proposed	$20,000,000			B
B	West	ATC LLC	884	884	6/1/2010	Spring Green	Capacitor bank		69		32 Mvar	install 2x 16.3 Mvar capacitor banks	WI			Proposed	$1,200,000			B
B	West	ATC LLC	887	887	6/1/2011	Bain	New 345 kV bus		345			construct 345 kV bus	WI			Proposed	$2,100,000			B
B	West	ATC LLC	888	888	6/1/2009	Plains 345-138 kV	transformer	2	345	138	500	second 500 MVA transformer	MI			Proposed	$5,400,000			B
B	West	ATC LLC	889	889	10/1/2007	Aspen	Substation relocation		69			Brule substation rename/relocation	MI			Planned	$5,700,000			B
B	West	ATC LLC	1268	1986	6/1/2009	Artesian	Capacitor bank				49	install 2x 24.5 Mvar capacitor banks	WI			Proposed				B

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App ABC	Region	Reporting Source	PrjID	Facil ID	Expected ISD	From Sub	To Sub or Equipment	Ckt	High kV	Low kV	Ratings	Upgrade Description	State	Miles Upg	Miles New	Planning Status	Estimated Cost	C.S.	P.S.	M07 ABC
B	West	ATC LLC	1268	1987	6/1/2009	Kilbourn	Capacitor bank				32.6	install 2x 24.5 Mvar capacitor banks	WI			Proposed				B
B	West	ATC LLC	1269	1988	6/1/2013	Arcadian 345-138kV	transformer	1	345	138	500	replace Arcadian 345/138kV transformer #2 & #3	WI			Proposed	$3,500,000			B
B	West	ATC LLC	1270	1989	6/1/2011	Arcadian	Waukesha	2	138		426	Increase line clearance	WI	4.0		Proposed	$400,000			B
B	West	ATC LLC	1270	1990	6/1/2011	Arcadian	Waukesha	1	138		426	Increase line clearance	WI	4.0		Proposed	$400,000			B
B	West	ATC LLC	1279	2105	6/1/2009	North Beaver Dam 138			138		49 Mvar		WI			Proposed	$1,800,000			B
B	West	ATC LLC	1280	2106	6/1/2008	South Lake Geneva 69			69		16.33 Mvar	new capacitor	WI			Proposed	$800,000			B
B	West	ATC LLC	1280	2107	6/1/2010	South Lake Geneva 69			69		16.33 Mvar	add second capacitor	WI			Proposed	$700,000			B
B	West	ATC LLC	1282	2109	6/1/2008	Osceola 69			69		10.8 Mvar	Add two 5.4 Mvar 138 kV Capacitor banks at the C	MI			Proposed				B
B	West	ATC LLC	1284	2110	6/1/2011	Albers	Tie	1	138				WI			Proposed	$0			B
B	West	ATC LLC	1284	2111	6/1/2011	Racine	Albers	1	138		345/477		WI	8.0		Proposed	$4,181,904			B
B	West	ATC LLC	1284	2112	6/1/2011	Racine	Somers	1	138		345/477		WI			Proposed				B
B	West	ATC LLC	1284	2113	6/1/2011	Albers	Somers	1	138		345/477		WI			Proposed				B
B	West	ATC LLC	1353	1993	12/31/2009	Hiawatha	Pine River	1	69		191 MVA SE	Maintenance rebuild of 69kV at 138kV standards	MI			Proposed				B
C>B	West	ATC LLC	1553	3101	6/1/2009	Hiawatha	Capacitor bank		138		16.33 MVAR		MI			Planned	$615,283			B
C>B	West	ATC LLC	1554	3102	6/1/2010	Indian Lake	Capacitor bank		138		16.33 MVAR		MI			Planned	$584,007			B
C>B	West	ATC LLC	1622	3256	6/1/2013	Oak Creek	St Rita	1	138		293/293	Increase clearance of the Oak Creek-St Rita 138-k	WI			Proposed				B
C>B	Central	CWLP	1552	2651	10/1/2009	Interstate	Holland/East Springfield	1	138		271	Loop Holland to East Springfield 1384 line through	IL			Planned	$1,500,000			B
B	Central	DEI	1556	3104	5/1/2011	Wheatland	Whitestown	1	345			New	IN		111.0	Proposed	$113,000,000			B
B	Central	DEI	1557	3105	5/1/2011	Wheatland	Bloomington	1	345			New	IN		61.0	Proposed	$95,140,000			B
B	Central	DEI	1557	3106	5/1/2011	Bloomington	Pritchard	1	345			New	IN		15.0	Proposed				B
B	Central	DEI	1557	3107	5/1/2011	Pritchard	Franklin	1	345			New	IN		24.0	Proposed				B
B	Central	DEI	1557	3108	5/1/2011	Franklin	Hanna	1	345			New	IN		2.8	Proposed				B
B	Central	DEI	1558	3109	5/1/2011	Petersburg	Francisco	1	345		1195 MVA	Upgrade to fix 1st contingency for the Wheatland b	IN			Proposed	$6,420,000			B
B	Central	DEI	1558	3110	5/1/2011	Petersburg	Thompson	1	345		1195 MVA	Upgrade to fix 1st contingency for the Wheatland b	IN			Proposed	$5,015,000			B
B	Central	DEM	1264	1981	6/1/2011	Speed			345	138	717	Replace existing 345/138 transformer at Speed wit	IN			Proposed	$5,000,000			B
B	Central	DEM	1504	2579	12/1/2007	Honda			138			New substation for Honda in Greensburg	IN			Planned	$0			B
B	Central	DEM	1505	2580	12/31/2007	HE Owensville North			138			Loop Gibson to Princeton 13863 line through new	IN			Planned	$0			B
B	Central	DEM	1507	2582	7/9/2007	Vectren Francisco			345			345kV interconnection in the Gibson to Vectren Du	IN			Planned	$0			B
B	Central	DEM	1510	2586	6/1/2008	Wabash River	TH Water St		138		191	Uprate conductor to 100C temperature	IN			Planned	$120,282			B
B	Central	DEM	1514	2590	6/1/2009	Wabash River	Staunton		230		498	Uprate Wabash River to Staunton 23002 to 100C s	IN			Planned				B
C>B	Central	DEM	1515	2591	10/1/2009	Speed	Relays		345			Replace Speed relays for the LGEE Trimble additio	IN			Planned	$0			B
B	Central	DEM	1563	3115	12/31/2007	Todhunter	AK Steel	1	138		306	Replace F5686 existing conductor with 954ACSR (	OH	0.7		Planned	$300,000			B
C>B	Central	DEM	1566	3118	10/15/2008	Rockies Express (REX)	AK Steel	1	138		306	Replace F5682 existing conductor with 954ACSR (	OH	1.5		Planned	$600,000			B
C>B	Central	DEM	1568	3120	6/1/2009	Qualitech	transformer	1	345	138	300	Qualitech Sub- Install one 345/138kv, 300Mva Xtr	IN			Planned	$4,561,674			B
C>B	Central	DEM	1569	3121	6/1/2009	Qualitech	Pittsboro	1	138		306	Construct new 138kv line, Qualitech to Pittsboro, a	IN		3.3	Planned	$1,507,856			B
C>B	Central	DEM	1570	3122	6/1/2009	Plainfield South	Pittsboro	1	138		306	Convert the existing 69KV (69144) line from Plainfi	IN	17.6		Planned	$4,139,000			B
B	East	FE	1324	2190	6/1/2009	Wallbridge Junction	Maclean	1	138		308/375 MVA	Line Reconductor	OH	0.5		Proposed	$247,900			B
B	East	FE	1339	2203	6/1/2010	Maysville	capacitor bank		138			Capacitor Bank Addition	OH			Proposed	$451,700			B
C>B	East	FE	1598	2681	12/1/2008	Stryker	Richland	1	138		152/166 MVA	New Line from 3 terminal lines.	OH	17.1		Planned	$68,500			B
C>B	East	FE	1598	2682	12/1/2008	Wauseon	Midway	1	138		158/190 MVA	New Line from 3 terminal lines.	OH	16.8		Planned				B
C>B	East	FE	1598	2683	12/1/2008	Napoleon Muni	Ridgeville	1	138		161/194 MVA	New Line from 3 terminal lines.	OH	15.7		Planned				B
C>B	East	FE	1599	2684	6/1/2009	Lemoyne	Oregon	1	138		286/286 MVA	New Line from 3 terminal lines.	OH	11.8		Planned	$1,020,100			B
C>B	East	FE	1599	2685	6/1/2009	Frey	Maclean	1	138		241/292 MVA	New Line from 3 terminal lines.	OH	3.9		Planned				B
C>B	East	FE	1599	2686	6/1/2009	Lemoyne	Maclean	1	138		241/292 MVA	New Line from 3 terminal lines.	OH	10.1		Planned				B
C>B	East	FE	1605	2696	12/1/2011	Brim	Midway	2	138		161/179 MVA	New Line	OH	13.2		Proposed	$800,000			B
C>B	East	FE	1605	2697	12/1/2011	Brim	Lemoyne	2	138		161/179 MVA	New Line	OH	12.2		Proposed				B
C>B	East	FE	1608	2700	6/1/2010	Ashtabula	Substation	1	345	138	268/448 MVA	New 345/138 kV Transformer	OH			Proposed	$10,468,849			B
C>B	East	FE	1611	2703	6/1/2012	Avon	Fox	1	345		1195/1195 MVA	New Line	OH		18.0	Proposed	$19,500,000			B
C>B	East	FE	1612	2704	6/1/2010	Cranberry	Substation		500			New Substation	PA			Planned	$16,568,983			B
C>B	East	FE	1612	2705	6/1/2010	Cranberry	Substation	1	500	138		New 500/138 kV transformer	PA			Planned				B
C>B	East	FE	1612	2706	6/1/2010	Hoytdale	Cranberry	1	138		246/246 MVA	New Line	PA	1.0		Planned				B
C>B	East	FE	1612	2707	6/1/2010	Cranberry	Fernway	1	138		246/246 MVA	New Line	PA	1.0		Planned				B
C>B	East	FE	1612	2708	6/1/2010	Jackson	Cranberry	1	138		278/339 MVA	New Line	PA	1.0		Planned				B
C>B	East	FE	1612	2709	6/1/2010	Cranberry	Epworth	1	138		278/339 MVA	New Line	PA	1.0		Planned				B

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B	West	GRE	602	802	6/1/2012	Brownton	McLeod	1	115				MN		9.0	Proposed	$4,675,000			B
B	West	GRE/MPC/XEL	286	1104	7/1/2012	Alexandria SS	Waite Park	1	345		2085	Add a new 345 kV line from Alexandria Switching S	MN		64.5	Proposed	$98,362,500			B
B	West	GRE/MPC/XEL	286	2640	7/1/2012	Waite Park	Monticello	1	345		2085	Add a new 345 kV line from Waite Park to Montice	MN		27.9	Proposed	$42,547,500			B
B	West	GRE/MPC/XEL	286	2641	7/1/2012	Alexandria SS	Transfomer		345	115	448	new transformer	MN			Proposed	$4,500,000			B
B	West	GRE/MPC/XEL	286	2642	7/1/2012	Waite Park	Transfomer		345	115	448	new transformer	MN			Proposed	$4,500,000			B
B	West	GRE/MPC/XEL	287	1105	7/1/2012	Maple River	Alexandria SS	1	345		2085	Add a new 345 kV line from Maple River to Alexan	MN/ND		110.8	Proposed	$117,448,000			B
B	West	GRE/XEL	603	801	6/1/2012	Alexandria	West St. Cloud	1	115		310		MN		75.0	Proposed	$36,954,688			B
B	West	GRE/XEL	1203	1881	6/1/2011	Brookings County	Lyon County 345 kV	1	345		2066	new line	SD/MN		49.0	Proposed	$39,200,000			B
B	West	GRE/XEL	1203	1882	6/1/2011	Lyon County	Franklin	1	345		2066	new line	MN		44.0	Proposed	$35,200,000			B
B	West	GRE/XEL	1203	1883	6/1/2011	Lyon County	Franklin	2	345		2066	new line	MN		44.0	Proposed	$17,600,000			B
B	West	GRE/XEL	1203	1884	6/1/2011	Franklin	Helena	1	345		2066	new line	MN		67.0	Proposed	$53,600,000			B
B	West	GRE/XEL	1203	1885	6/1/2011	Franklin	Helena	2	345		2066	new line	MN		67.0	Proposed	$26,800,000			B
B	West	GRE/XEL	1203	1886	6/1/2011	Helena	Lake Marion	1	345		2066	new line	MN		16.0	Proposed	$12,800,000			B
B	West	GRE/XEL	1203	1887	6/1/2011	Lake Marion	Hampton Corner	1	345		2066	new line	MN		18.0	Proposed	$14,400,000			B
B	West	GRE/XEL	1203	1888	6/1/2011	Lyon County	Hazel	1	345		2066	new line	MN		22.0	Proposed	$18,480,000			B
B	West	GRE/XEL	1203	1889	6/1/2011	Hazel	Minnesota Valley	1	230		388	new line	MN		8.0	Proposed	$3,600,000			B
B	West	GRE/XEL	1203	1891	6/1/2011	Brookings County	Toronto	1	115		310	new line	SD		20.0	Proposed	$7,000,000			B
B	West	GRE/XEL	1203	1893	6/1/2011	Lyon County	Transfomer	1	345	115	448	new transformer	MN			Proposed	$6,000,000			B
B	West	GRE/XEL	1203	1894	6/1/2011	Lake Marion	Transfomer	1	345	115	448	new transformer	MN			Proposed	$6,000,000			B
B	West	GRE/XEL	1203	1895	6/1/2011	Hazel	Transfomer	1	345	230	336	new transformer	MN			Proposed	$6,000,000			B
B	West	GRE/XEL	1203	1896	6/1/2011	Hazel	Transfomer	2	345	230	336	new transformer	MN			Proposed	$4,000,000			B
B	West	GRE/XEL	1203	1897	6/1/2011	Franklin	Transfomer	1	115	69	70	Upgrade 47 MVA to 70 MVA	MN			Proposed	$4,000,000			B
B	West	GRE/XEL	1203	1898	6/1/2011	Morris	Transfomer	2	230	115	150	Upgrade 100 MVA to 150 MVA	MN			Proposed	$4,000,000			B
B	West	GRE/XEL	1203	1899	6/1/2011	Willmar	Transfomer	2	115	69	112		MN			Proposed	$3,000,000			B
B	West	GRE/XEL	1203	2649	6/1/2011	Franklin	Transfomer	1	345	115	448	new transformer	MN			Proposed	$4,000,000			B
C>B	Central	HE	1635	3299	6/1/2009	Ramsay Primary	345kV Ring Bus	1	345		2000 AMP	Rebuild	IN			Planned	$5,000,000			B
C>B	Central	IPL	897	907	6/1/2012	Thompson 345-138 kV	transformer	1	345	138	500 MVA	New 345/138kV Autotransformer	IN			Proposed	$4,500,000			B
B	Central	IPL	1634	3298	6/1/2008	Petersburg	Vincennes Jct	1	138		249	Change CT Ratio At Petersburg to 1200A	IN			Planned	$2,500			B
B	West	MDU	1479	2240	11/1/2007	Cabin Creek	Switchyard & 115/60 kV xfmr		115	60	90 MVA	Tap on Baker - Glendive 115 kV line	MT			Planned				B
B	East	METC	1436	2440	5/1/2008	Four Mile 138kV	Wealthy Street 138kV	1	138	12.5		Install a second distribution transformer served fro	MI			Proposed	$56,000			B
B	West	MP	1292	2123	6/1/2011	ETCO	Forbes	1	115		122/134	Increase ground clearance	MN			Proposed	$400,000			B
B	East	NIPS	919	974	12/1/2008	Lagrange	Transformer	1	138	69	168	Replace #1 Transformer - Increase Capacity	IN			Proposed	$1,593,300			B
B	East	NIPS	923	972	5/1/2007	Plymouth	Transformer	3	138	69	168	Add 3rd 138/69 kV Transformer	IN			Proposed	$2,689,400			B
B	West	OTP	549	1530	1/1/2008	Jamestown	Reactor		115		25 Mvar	Add a 1 x 25 MVAr reactor at OTP Jamestown sub	ND			Proposed	$436,672			B
B	West	OTP	973	1521	11/1/2009	Big Stone 230	Canby 230	1	230		1145	Build new 230 kV line with 2-1272 ACSR for Big St	MN/SD		55.0	Planned	$41,250,000			B
B	West	OTP	973	1523	11/1/2009	Canby 230/115 kV	transformer		230	115	336	Install a 230/115 kV Transformer for Big Stone II G	MN			Planned	$6,100,000			B
B	West	OTP	973	1524	7/1/2010	Big Stone 230	Browns Valley 230 kV		230		390	Upgrade substation equipment at Browns Valley to	SD	38.7		Planned	$2,000,000			B
B	West	OTP	973	1522	11/1/2010	Canby 230	Granite Falls 230	1	230		1145	Build new 230 kV line with 2-1272 ACSR for Big St	MN	39.2		Planned	$29,400,000			B
B	West	OTP	973	1517	6/1/2011	Johnson Jct. 230	Morris 230	1	230		520	Convert existing 115 kV line to 230 kV with 1272 A	MN	15.4		Planned	$9,400,000			B
B	West	OTP	973	1518	6/1/2011	Johnson Jct. 230/115 kV	transformer	1	230	115	112	Install a 230/115 kV Transformer for Big Stone II G	MN			Planned	$3,000,000			B
B	West	OTP	973	1525	6/1/2011	Morris 230/115 kV	transformer	1	230	115	336	Replace existing transformer at Morris with 336 MV	MN			Planned	$6,100,000			B
B	West	OTP	973	1515	11/1/2012	Big Stone 230	Ortonville 230	1	230		520	Build new 230 kV line with 1272 ACSR for Big Stor	MN/SD		6.5	Planned	$2,400,000			B
B	West	OTP	973	1516	11/1/2012	Ortonville 230	Johnson Jct. 230	1	230		520	Convert existing 115 kV line to 230 kV with 1272 A	MN	24.6		Planned	$15,100,000			B
B	West	OTP/MPC	971	235	12/31/2010	Winger 230-115 kV	transformer	1	230	115	187	Final Design not complete - Either add 2nd 230/11	MN			Proposed	$3,715,351			B
B	Central	Vectren	1002	1566	5/31/2009	Northeast	Oak Grove	77	138		287/287	new line	IN		5.0	Planned	$2,800,000			B
B	Central	Vectren	1002	1567	5/31/2009	Oak Grove	Culley	77	138		287/287	new line	IN		10.0	Planned	$5,700,000			B
B	Central	Vectren	1023	1968	5/31/2009	Scott Township 138/69 kV	Substation		138	69	168/176	new substation with one 138/69 kV transformer an	IN			Planned	$10,000,000			B
B	Central	Vectren	1023	1969	5/31/2009	Scott Township	Elliott	74	138		287/287	new line	IN		6.0	Planned	$3,900,000			B
C>B	East	WPSC	1209	1904	8/1/2007	Hersey	Bus Upgrade		69			Convert Single Bus to Ring Bus	MI			Proposed	$2,300,000			B
C>B	East	WPSC	1210	1905	8/1/2007	Lewiston	Breaker		69			Add Breaker at Lewiston	MI			Proposed	$520,000			B
B	East	WPSC	1211	1906	8/1/2007	Grand Traverse	Grawn		69		102.4 MVA	Rebuild Overloaded Line	MI	5.2		Proposed	$1,200,000			B
C>B	East	WPSC	1213	1908	8/1/2007	Vestaburg	6MVAR cap. Bank		69			Add 6MVAR at Vestaburg Sub.	MI			Proposed	$3,000			B
C>B	East	WPSC	1217	1912	8/1/2008	Grawn	Bus Upgrade		69			Convert Single Bus to Ring Bus	MI			Proposed	$1,900,000			B
C>B	East	WPSC	1218	1913	8/1/2009	Atlanta	Bus Upgrade		69			Convert Single Bus to Ring Bus	MI			Proposed	$1,900,000			B

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C>B	East	WPSC	1219	1914	8/1/2009	Lake County	Star Lake		69		102.4 MVA	Rebuild Overloaded Line	MI	7.7		Proposed	$1,800,000			B
B	East	WPSC	1221	1916	8/1/2010	Redwood	New Era		69		102.4MVA	Rebuild Overloaded Line	MI	7.5		Proposed	$1,500,000			B
C>B	East	WPSC	1222	1917	8/1/2010	Lake County	Bus Upgrade		69			Convert Single Bus to Ring Bus	MI			Proposed	$3,800,000			B
B	East	WPSC	1274	1996	10/1/2007	Allendale	Blendon		69		63.2/82.2MVA	Rerate overloaded line	MI	2.1		Proposed	$150,000			B
B	East	WPSC	1275	1997	10/1/2007	Boyne City	Wilson		69		43.4/56.4MVA	Rerate overloaded line	MI	3.0		Proposed	$200,000			B
B	East	WPSC	1276	1998	10/1/2010	Burnips	Goodwin		69		43.4/56.4MVA	Rerate overloaded line	MI	13.1		Proposed	$900,000			B
B	East	WPSC	1277	1999	10/1/2011	Wayland	Goodwin		69		43.4/56.4MVA	Rerate overloaded line	MI	4.6		Proposed	$350,000			B
B	East	WPSC	1278	2000	10/1/2007	North Shade	capacitor		69		6 Mvar	Fix Undervoltage Problem	MI			Proposed	$150,000			B
B	East	WPSC	1299	2129	8/1/2011	Lake County 138	Lake County 69		69		168MVA	Add 168MV transformer	MI			Proposed	$2,600,000			B
B	East	WPSC	1311	2166	8/1/2011	Copemish	Karlin		69		43.4/56.4	Rerate overloaded line	MI			Proposed	$1,400,000			B
B	East	WPSC	1312	2167	8/2/2011	Grawn	Karlin		69		43.4/56.4	Rerate overloaded line	MI			Proposed	$650,000			B
B	East	WPSC	1313	2168	8/3/2011	Baldwin	Plains X		69		37.8/49.1	Rerate overloaded line	MI			Proposed	$700,000			B
B	East	WPSC	1314	2169	8/4/2011	Plains X	Star Lake		69		43.4/56.4	Rerate overloaded line	MI			Proposed	$700,000			B
B	East	WPSC	1315	2170	8/5/2011	Potter	Grand Traverse		69		43.4/56.4	Rerate overloaded line	MI			Proposed	$225,000			B
C>B	East	WPSC	1574	3126	7/1/2013	Wayland	Wayland Distribution	1	69		43.4/56.4	Rerate Overloaded Line	MI	0.0		Proposed	$50,000			B
C>B	East	WPSC	1575	3127	7/1/2009	Portland			69			Add 18MVAR Cap bank at Portland	MI			Proposed	$750,000			B
C>B	East	WPSC	1576	3128	7/1/2009	Chester			69			Add 12MVAR Cap bank at Chester	MI			Proposed	$750,000			B
C>B	East	WPSC	1577	3129	7/1/2008	Copemish	Bretheren	1	69		43.4/56.4	Rerate Overloaded Line	MI	10.8		Proposed	$1,621,500			B
C>B	East	WPSC	1578	3130	7/1/2008	Garfield X	Hall Street	1	69		43.4/56.4	Rerate Overloaded Line	MI	3.7		Proposed	$559,500			B
C>B	East	WPSC	1579	3131	7/1/2008	Garfield X	Grawn	1	69		205/266	Rebuild Overloaded Line	MI	7.7		Proposed	$1,152,000			B
C>B	East	WPSC	1580	3132	7/1/2013	Redwood	Hart	1	69		37.8/49.1	Rerate Overloaded Line	MI	1.8		Proposed	$265,500			B
C>B	East	WPSC	1581	3233	7/1/2011	East Jordan X	Graves X	1	69		43.4/56.4	Rerate Overloaded Line	MI	7.1		Proposed	$1,071,000			B
C>B	East	WPSC	1582	3134	7/1/2013	Alba	Graves Junction	1	69		43.4/56.4	Rerate Overloaded Line	MI	4.7		Proposed	$708,000			B
C>B	East	WPSC	1583	3135	7/1/2008	Bretheren	Bass Lake	1	69		43.4/56.4	Rerate Overloaded Line	MI	18.1		Proposed	$2,716,500			B
C>B	East	WPSC	1584	3136	7/1/2013	Shelby	New Era	1	69		37.8/49.1	Rerate Overloaded Line	MI	4.2		Proposed	$631,500			B
C>B	East	WPSC	1585	3137	7/1/2009	Bagley X	Gaylord Distribution	1	69		43.4/56.4	Rerate Overloaded Line	MI	3.3		Proposed	$498,000			B
C>B	East	WPSC	1586	3138	7/1/2008	Boyne City	Hayes X	1	69		43.4/56.4	Rerate Overloaded Line	MI			Proposed	$50,000			B
C>B	East	WPSC	1586	3144	8/1/2008	Advance	Wilson	1	69		198/257.4	Rebuild Overloaded line	MI	4.7		Proposed	$705,000			B
C>B	East	WPSC	1586	3140	12/31/2008	Gaylord	Kerridge	1	69		198/257.4	Rebuild Overloaded line	MI			Proposed	$0			B
C>B	East	WPSC	1586	3141	12/31/2008	Kerridge	Alpine	1	69		198/257.4	Rebuild Overloaded line	MI	3.4		Proposed	$511,500			B
C>B	East	WPSC	1586	3142	12/31/2008	Alpine	Elmira	1	69		198/257.4	Rebuild Overloaded line	MI	3.6		Proposed	$541,500			B
C>B	East	WPSC	1586	3139	7/1/2009	Petoskey Distribution	Hayes X	1	69		43.4/56.4	Rerate Overloaded Line	MI	10.5		Proposed	$1,572,000			B
C>B	East	WPSC	1586	3143	8/1/2010	Elmira	Advance	1	69		198/257.4	Rebuild Overloaded line	MI	16.3		Proposed	$2,439,000			B
C>B	East	WPSC	1586	3145	8/1/2010	Wilson	Boyne City	1	69		198/257.4	Rebuild Overloaded line	MI	3.0		Proposed	$456,000			B
C>B	East	WPSC	1586	3146	8/1/2010	Boynce City	Hayes X	1	69		198/257.4	Rebuild Overloaded line	MI			Proposed	$0			B
C>B	East	WPSC	1586	3147	8/1/2010	Hayes X	Petoskey	1	69		198/257.4	Rebuild Overloaded line	MI	10.5		Proposed	$1,572,000			B
C>B	East	WPSC	1586	3148	8/1/2010	Petoskey	Petoskey Distribution	1	69		198/257.4	Rebuild Overloaded line	MI			Proposed	$0			B
C>B	East	WPSC	1586	3149	8/1/2010	Petoskey Distribution	Oden	1	69		198/257.4	Rebuild Overloaded line	MI	5.2		Proposed	$786,000			B
C>B	East	WPSC	1588	2652	8/1/2013	Casnovia	Cap bank	1	69			Add 6MVAR cap bank to Casnovia Substation	MI			Proposed	$750,000			B
C>B	West	XEL	675	1364	6/1/2011	Westgate	Scott County	1	115		310	upgrade line	MN	20.1		Proposed				B
B	West	XEL	751	3019	12/1/2007	Nobles Co	Reactor #1		34.5		-50 Mvar	New reactor	MN			Proposed	$200,000			B
B	West	XEL	1285	2114	6/1/2011	Glencoe	West Waconia	1	115		310/341	Build 18 miles 115 kV line from Glencoe - West Wa	MN		18.0	Proposed				B
B	West	XEL	1297	2125	6/1/2011	Oakwood	Monticello	1	115		310/341	Reconductor with 795 ACSS	MN	11.2		Proposed				B
B	West	XEL	1297	2126	6/1/2011	Oakwood	Hassan	1	115		310/341	Reconductor with 795 ACSS	MN	19.0		Proposed				B
C>B	West	XEL	1370	2293	5/1/2009	Pine Lake	Rush River	1	161		-	Relocate the 69 kV rush River substation to existin	WI			Proposed				B
C>B	West	XEL	1370	2294	5/1/2009	Rush River	Crystal Cave	1	161		-	Relocate the 69 kV rush River substation to existin	WI			Proposed				B
C>B	West	XEL	1371	2295	6/1/2009	Black Dog	Wilson	2	115		310	Reconductor	MN			Planned	$900,000			B
C>B	West	XEL	1373	2297	6/1/2010	Ft. Ridgeley	West New Ulm	1	115		620	new Line	MN			Planned				B
C>B	West	XEL	1373	2298	6/1/2010	West New Ulm	New Ulm	1	69		84	Reconductor	MN			Planned				B
C>B	West	XEL	1375	2302	12/31/2009	Lake Yankton	SW Marshall	1	115		310	New 115 kV line	MN			Planned	$5,000,000			B
C>B	West	XEL	1375	2300	6/1/2010	Hazel Creek	Minnesota Valley	1	115		310	New 1115 kV Line	MN			Proposed	$5,000,000			B
C>B	West	XEL	1545	2624	12/1/2009	South Bend	Wilmarth	1	115		139	Line terminations at Wilmarth and South Bend	MN			Planned	$280,000			B
C>B	West	XEL	1546	2630	6/1/2008	Hyland Lake	Dean Lake	1	115		370	Upgrade 3.2 miles of 115 kV line with 2-795 ACSR	MN			Planned	$1,057,000			B
C>B	West	XEL/GRE	1545	2623	12/1/2009	New South Bend 161/115/69 kV Substation						new Substation South of Wimarth. The 161/115 kV	MN			Planned	$6,405,000			B

MTEP07 Appendix B - Facility Table - 10/04/07

App ABC	Region	Reporting Source	PrjID	Facil ID	Expected ISD	From Sub	To Sub or Equipment	Ckt	High kV	Low kV	Ratings	Upgrade Description	State	Miles Upg	Miles New	Planning Status	Estimated Cost	C.S.	P.S.	M07 ABC
C>B	West	XEL/GRE	1545	2625	12/1/2009	South Bend	Ballard Corner	1	115		310	Upgrade the existing 69 kV line from South Bend -	MN			Planned	$4,300,000			B
C>B	West	XEL/GRE	1545	2626	12/1/2009	Hungry Hollow	Pohl tap	1	115		310	Upgrade the existing 69 kV line from Hungry Hollo	MN			Planned	$950,000			B
C>B	West	XEL/GRE	1545	2627	12/1/2009	Pohl tap	Pohl	1	115		310	Upgrade the existing 69 kV line from Pohl - Pohl ta	MN			Planned				B
C>B	West	XEL/GRE	1545	2628	12/1/2009	Pohl	Eastwood	1	115		194	Reterminate the existing 69 kV line from Pohl - Eas	MN			Planned	$440,000			B
C>B	West	XEL/GRE	1545	2629	12/1/2009	Pohl Substation						Upgrade the Pohl substation from 69 kV to 115 kV	MN			Planned	$540,000			B
Projects after the Plan Year					1/1/2014															B
C>B	West	ATC LLC	1624	3241	6/1/2014	Portage	Trienda	2	138		373/430	uprate X-67	WI	3.4		Proposed				B
B	West	ATC LLC	434	2063	6/1/2015	Butternut	Capacitor bank		138		28.8 Mvar		WI			Proposed	$1,050,000			B
B	West	XEL/DPC	1024	1669	12/15/2015	North La Crosse	North La Crosse Tap	1	161		304	upgrade DPC, new XEL	WI	1.0	1.0	Proposed	$400,000			B
B	West	XEL/DPC	1024	1670	12/15/2015	North La Crosse	North La Crosse Tap	2	161		304	upgrade DPC, new XEL	WI	1.0	1.0	Proposed	$400,000			B
B	West	XEL/DPC/RPU	1024	2647	12/15/2015	Belvidere	North La Crosse	1	345		2050	new line	MN		40.0	Proposed	$79,600,000			B
B	West	XEL/DPC/RPU/	1024	1673	12/15/2015	Hampton Corner	North Rochester	1	345		2050	new line	MN		46.6	Proposed	$92,734,000			B
B	West	XEL/DPC/RPU/	1024	1674	12/15/2015	North Rochester	Belvidere	1	345		2050	new line	MN		47.0	Proposed	$79,600,000			B
B	West	XEL/DPC/RPU/	1024	1675	12/15/2015	North Rochester	Transformer	1	345	161	448	new transformer	MN			Proposed	$3,800,000			B
B	West	XEL/DPC/RPU/	1024	1676	12/15/2015	North La Crosse	Transformer	1	345	161	448	new transformer	WI			Proposed	$3,800,000			B
B	West	XEL/DPC/RPU/	1024	1677	12/15/2015	North Rochester	Northern Hills	1	161		400	new line	MN		12.1	Proposed	$13,068,000			B
B	West	XEL/DPC/RPU/	1024	1678	12/15/2015	North Rochester	Chester	1	161		400	new line	MN		25.4	Proposed	$27,410,400			B
B	West	XEL/DPC/RPU/	1024	3274	12/15/2015	North La Crosse	La Crosse	1	161		400	upgrade line	WI	8.8		Proposed				B
B	West	ATC LLC	569	1250	6/1/2016	South Lake Geneva	White River	1	138		355	line to new T-D substation	WI		3.0	Proposed	$2,500,000			B
B	West	ATC LLC	569	1251	6/1/2016	South Lake Geneva 138-69	transformer	1	138	69			WI			Proposed	$1,973,000			B
B	West	ATC LLC	573	1265	6/1/2016	North Madison	West Middleton	1	345		1200		WI		20.0	Proposed	$46,700,000			B
B	Central	DEM	1521	2597	6/1/2016	Bloomington 230 (terminal e	Bloomington NW		138		191	Replace the 600A 13836 bkr disconnect switches \	IN			Planned	$233,455			B
B	West	OTP	585	589	6/1/2017	Pelican Rapids	Pelican Rapids Turkey Plan	1	115		85	Convert an existing 41.6 kV line to 115 kV	MN	2.5		Planned	$858,869			B
B	West	ATC LLC	89	103	6/1/2018	Mill Road (renamed, was La	transformer		345	138	500	transformer	WI			Proposed	$29,200,000			B
B	West	ATC LLC	89	3246	6/1/2018	Mill Rd	Cypress	1	345		488/488	Tap Arcadian-Cypress into Mill Rd	WI			Proposed				B
B	West	ATC LLC	89	3247	6/1/2018	Mill Rd	Arcadian	1	345		488/488	Tap Arcadian-Cypress into Mill Rd	WI			Proposed				B
B	West	ATC LLC	89	3248	6/1/2018	Mill Rd	Bark River	1	138		287/287	Tap Bark River-Germantown into Mill Rd	WI			Proposed				B
B	West	ATC LLC	89	3249	6/1/2018	Mill Rd	Germantown	1	138		287/287	Tap Bark River-Germantown into Mill Rd	WI			Proposed				B
B	West	ATC LLC	89	3250	6/1/2018	Mill Rd	Sussex	1	138		252/301	TapSussex-Tamarack into Mill Rd	WI			Proposed				B
B	West	ATC LLC	89	3251	6/1/2018	Mill Rd	Tamarack	1	138		252/301	TapSussex-Tamarack into Mill Rd	WI			Proposed				B
B	West	ATC LLC	341	477	6/1/2018	Concord 345/138 kV	transformer		345	138	500		WI			Proposed	$12,900,000			B
B	West	ATC LLC	341	483	6/1/2018	Rockdale	Concord (rebuild to dbl ckt 1	1	345		1200	rebuild to dbl ckt 138/345	WI	22.6		Proposed	$22,200,000			B
B	West	ATC LLC	341	893	6/1/2018	Concord	Bark River		345		815	new line	WI		19.0	Proposed	$50,300,000			B
B	West	ATC LLC	341	894	6/1/2018	Bark River	transformer		345	138	500	transformer	WI			Proposed	$8,400,000			B
B	West	ATC LLC	341	895	6/1/2018	Bark River	Mill Road		345		815	convert 138 to 345 kV	WI	11.0		Proposed	$800,000			B
B	Central	AmerenIP	1232	2219		Tilden	Fayetteville	1				tap Tilden-Fayetteville (L1526) for construction pov	IL			Proposed				B
B	Central	AmerenIP	1527	2711		Pana	Route 51		138			upgrade terminal equipment	IL			Proposed	$250,000			B

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
C			**Appendix C**											C
A>C	Central	Ameren	143	Cahokia-Pinckneyville-1 230 kV	Cahokia - N. Coulterville section of Cahokia-Pinckneyville-1 230 kV - Increase ground clearance	IL		Other	Excluded	$644,600	6/1/2011	230		C
C	Central	Ameren	1237	Cambell-Euclid-Page 138 kV	Rebuild 5.25 miles dbl-ckt. 138 kV	MO				$15,254,100	6/1/2010	138		C
C	Central	Ameren	1238	GM-Point Prairie 161 kV to AECI Enon Sub.	Extend 1 mile of 161 kV to AECI Enon Substation	MO				$1,279,700	6/1/2010	161		C
C	Central	Ameren	1240	Reconductor Sioux-Huster-1 and -3 138 kV	Reconductor 15 miles of Sioux-Huster-1 and 13 miles of Sioux-Huster-3	MO				$4,996,000	12/1/2010	138		C
C	Central	Ameren	1530	Gibson City Outlet Lines - Upgrade	Increase capability of Gibson City-Brokaw and Gibson City-Paxton 138 kV lines	IL				$23,144,084	6/1/2010	138		C
C	Central	Ameren	1538	Pana, North-Ramsey, East - Rebuild Line	Rebuild 18.43 miles of line for operation at 120 degrees C.	IL				$2,702,200	6/1/2011	138		C
C	Central	Ameren	1539	Roxford Substation - Install 345 kV PCB	Install 345 kV PCB on Roxford-Stallings line position	IL					6/1/2011	345		C
C	Central	AmerenIP	737	Bluff City 138 kV Substation	Bluff City 138 kV Substation - Install 138 kV breaker	IL				$1,756,400	6/1/2009	138		C
C	Central	AmerenIP	872	Mahomet-Champaign 138 kV Line 1592	Mahomet-Champaign 138 kV Line 1592 - Reconductor 1.55 miles of 477 kcmil ACSR from Mahomet Substation to Twr. 29	IL				$725,500	6/1/2008	138		C
C	Central	AmerenIP	1529	Brokaw-State Farm Line 1596 - Reconductor	Reconductor 3.3 miles of 138 kV line to 2000 A Summer Emergency capability	IL				$2,566,900	6/1/2010	138		C
C	Central	AmerenIP	1536	Latham-Mason City - Reconductor	Reconductor from Latham Tap to Kickapoo Tap	IL					6/1/2011	138		C
C	Central	AmerenIP	1540	Sidney-Windsor - Reconductor	Reconductor 13.1 miles to 1600 A Summer Emergency Capability	IL					6/1/2011	138		C
C	West	ATC LLC	1450	Cornell (4.5 ohm reactor) on Cornell - Fiebrantz138 kV line	Cornell (4.5 ohm reactor) on Cornell - Fiebrantz138 kV line	MN				$4,651,493	6/1/2008	138		C
C	West	ATC LLC	1555	Perkins Capacitor Banks	Install two 16.33 MVAR 138kV capacitor banks at Perkins substation	MI				$1,395,185	6/1/2009	138		C
C	West	ATC LLC	1621	New Birchwood-Lake Delton 138-kV line	Construct new Birchwood-Lake Delton 138-kV line	WI					6/1/2013	138		C
C	West	ATC LLC	1626	Summit Capacitor Banks	Install two 34.2 MVAR 69kV capacitor banks at Summit substation	WI					6/1/2010	138		C
C	West	ATC LLC	1628	Replace Columbia T22 345/138-kV Transformer	Replace Columbia T22 345/138-kV Transformer	WI					6/1/2013	345	138	C
B>C	Central	DEM	625	Pierce/Beckjord 345/138 kV transformer addition	Add 3rd 345/138kV transformer, 400MVA, from Pierce 345kV bus to Beckjord 138kV North bus.	OH		Other	Excluded	$2,659,515	6/1/2008	345	138	C
C	Central	DEM	841	Westwood Bk1 Limiting Equipment	Replace 1200A 138kV equipment with 2000A to allow full transformer rating.	IN				$554,000	6/1/2013	345	138	C
C	Central	DEM	1512	Ashland to Rochelle 138	Install underground 138 kV circuit from Ashland to Rochelle.	OH				$2,478,513	6/1/2010	138		C
C	Central	DEM	1560	Edwardsport 138kV cap	Install a 138kV 57.6MVAR capacitor at Edwardsport.	IN				$500,000	6/1/2010	138		C
C	Central	DEM	1561	Kokomo Webster St 230kv Ring bus	Retire existing 1600A circuit switcher and complete the Webster St ring in order to utilize the full capacity of the bundled 477 ACSS wire on the 23016 line.	IN				$399,580	6/1/2011	230		C
C	Central	DEM	1565	Carlisle to Hutchings 138kv line conversion	Convert existing 187 MVA - 69 KV line (DP&L - F6601) to 138 KV between Carlisle and DP&L Hutchings	OH				$2,315,946	12/31/2013	138		C

Project Information from Facility Table

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
B>C	East	FE	1317	Hayes Substation	Hayes Substation installed to split the Greenfield to Avery and Greenfield to Beaver 138 kV lines as well as the Davis Besse to Beaver 345 kV line. The 345 kV system will be tied into the 138 kV system via a 345/138 kV transformer at this substation.	OH				$11,000,000	6/1/2009	345	138	C
C	East	FE	1596	Lakeview Sub - Install 138kV Cap Bank	Install 1 - 50 MVAR Capcitor bank and 1 - breaker	OH				$806,357	6/1/2008	138		C
C	East	FE	1597	Galion - Add 138kV Cap Banks	Add (2) - 50 MVAR Cap Banks, plus a new breaker string to give each cap bank it's own position	OH				$1,645,789	6/1/2010	138		C
C	East	FE	1600	Beaver - Wellington New 138 kV Line	Build a new Beaver - Wellington 138 kV Line and establish a 138 kV ring bus at Wellington Substation.	OH				$5,020,000	6/1/2011	138		C
C	East	FE	1601	Chamberlin - Shalersville New 138 kV Line	Build a new Chamberlin - Shalersville 138 kV Line. Approximately 9.5 miles will be built to 345 kV standards w/2-954 ACSR and 2.5 miles will be wood pole 795 ACSR	OH				$3,150,273	6/1/2009	138		C
C	East	FE	1602	Clark-Broadview-E.Springfield: Create 138kV Loop around City of Springfield	Loop Clark-Urbana 138kV and E.Spring-Tangy 138kV lines in and out of Broadview Substation. New 138kV Substation at existing Broadview 69kV switching station with (2) 138/69kV transformers.	OH				$10,124,039	6/1/2010	138	69	C
C	East	FE	1603	E.Springfield-London-Tangy: New 138kV source to Springfield	Build new 138kV line from Tangy Substation to London Substation. Build new 138kV circuit from London to East Springfield Substation on existing open circuit position	OH				$12,914,379	6/1/2012	138		C
C	East	FE	1606	Barberton - South Akron - Install New 138 kV Line	Construct a new 8.1 mile Barberton - South Akron 138 kV line.	OH				$3,489,106	6/1/2009	138		C
C	East	FE	1607	Hanna Sub - Loop the Cham - Mansfield 345 kV Line in	Loop the Chamberlin - Mansfield 345 kV Line in and out of Hanna Substation creating a Chamberlin - Hanna and a Hanna - Mansfield 345 kV Line.					$4,940,700	6/1/2010	345		C
C	East	FE	1609	Tangy -Add 345/138kV Transformer, (2) 345kV BKR's, (1) 138kV BKR, additional substation work	Additional 345/138kV TR (150/200/250 MVA). Add (2) 345kV breakers. One to separate TR #3 and TR #4, and one for the new transformer	OH				$7,305,325	6/1/2009	345	138	C
C>B	East	FE	1610	SW Avon 92-AV-T New Transformer	Add new autotransformer to Avon Lake substation, along with station re-configuration to accomodate new transformer.	OH				$5,965,035	6/1/2009	345	138	C
C	West	GRE	1018	Little Falls - Pierz conversion to 115 kV	Convert Little Falls - Pierz 34 kV line to 115 kV operation	MN				$900,000	6/1/2011	115		C
C	West	GRE	1354	Dotson -Storden 161 and Dotson - Searles 161	Dotson -Storden 161 and Dotson - Searles 161	MN					12/31/2010	161	69	C
B>C	East	ITC	694	Saratoga Station	Saratoga 345/120 kV switching station	MI				$29,600,000	12/31/2009	345	120	C
C	East	ITC	902	Greenwood 345/120 Xmfr	Puts in new 345/120 kV Xfmr at Greenwood and constructs new Greenwood-Wabash 120 kV and Greenwood-Adams 120 kV	MI				$12,000,000	12/31/2008	345	120	C
B>C	East	ITC	903	Stephens - Bismark	Creates a Bismark-Stephens 230 kV line with a 230/120 kV Xfmr at Stephens, and also builds a new Stephens-Redrun 120 kV	MI				$9,000,000	12/31/2008	230	120	C

Project Information from Facility Table

App ABC	Region	Reporting Source	PrjID	Project Short Name	Project Description	State	State2	Allocation FF	Share Status	Estimated Project Cost	Project Expected ISD	Max kV	Min kV	M07 ABC
B>C	East	ITC	908	Lulu Station	Phase One - Construct a 345 kV switching station at the Lulu site, including 8 345 kV breakers and Cut in the Majestic - Lemoyne 345 kV circuit into new Lulu station and the Milan-Allen Junction-Monroe 3-4 345 kV circuit into new Lulu station. Phase Two - Split the Lulu to Lemoyne 345 kV circuit into a Lulu to Monroe 1-2 345 kV circuit and a Leymoyne to Monroe 3-4 345 kV circuit, creating a new 3 mile 345 kV double circuit tower line.	MI				$24,000,000	5/30/2008	345		C
C	East	ITC	909	230 kV Northwest	Tap one of the METC Thetford to Hampton 345 kV circuits west of the ITC Atlanta 120 kV station, build a new 2.3 mile 345 kV line from the tap to the Atlanta station, install a 345/230 kV transformer at Atlanta, build a new 13.6 mile 230 kV circuit from Atlanta to the Tuscola station, install a 230/120 kV transformer at Tuscola, convert 22.5 mile 120 kV circuit from Tuscola down to a new 345 kV switching station at the Hunters Creek station to 230 kV, install a 345/230 kV transformer and a 230/120 kV transformer at Hunters Creek, and tap the Belle River to Blackfoot 345 kV circuit at Hunters Creek.	MI				$48,000,000	5/30/2010	345	120	C
B>C	East	ITC	1012	Wyane - Newburg Split	Split existing six-wired 120 kV circuit from Wayne to Newburg creating a new 2.8 mile 120 kV circuit.	MI				$1,200,000	5/30/2007	120	120	C
B>C	East	ITC	1295	Quaker - Southfield	Adds a new 120 kV circuit from the Quaker station to the Southfield station.	MI					6/30/2010	120		C
C	East	ITC	1303	Arrowhead Bypass Switch	Places a normally open bypass switch at the 120 kV Arrowhead Station	MI				$940,000	5/31/2007	120		C
C	East	ITC	1550	Hager - Sunset 120 kV	Transposes the existing cabled line entrance of the Hager-Sunset 120 kV Line with the overhead line entrance of the Sunset-Southfield 120 kV line to increase the thermal rating of Hager-Sunset.	MI					5/31/2008	120		C
C	West	MDU	1356	Glenham - Reactors 230 115 Control high voltage on WAPA Bismarck - Oahe 230 kV line	Glenham - Reactors 230 115 Control high voltage on WAPA Bismarck - Oahe 230 kV line	ND					11/1/2009	230	115	C
A>C	East	METC	240	Garfiled - Hemphill 138 ckt 1	Garfiled - Hemphill 138 ckt 1, Sum rate 521	MI		Other	Excluded	$1,900,000	6/1/2011	138		C
A>C	East	METC	494	Battle Creek - Verona 138kV #1 Line	Remove Sag Limit	MI		Other	Excluded	$50,000	12/1/2007	138		C
B>C	East	METC	984	Denver 345/138 kV station	Build new 345/138 kV station, 50 miles 345 kV line, 60 miles 138 kV lines	MI				$77,132,000	6/1/2011	345		C
B>C	East	METC	987	Emmet - Stover 138 kV Line	Build 30 miles new 138 kV line, 795 ACSS	MI				$10,250,000	6/1/2013	138		C
C	East	METC	1428	Roosevelt substation	Add 345/138kV transformer and new 138kV line to Black River along with breakers at Roosevelt and Black River	MI				$16,000,000	5/1/2013	345	138	C
B>C	East	METC	1443	Milham	Install a second distribuiton transformer served from Milham-Upjohn 138kV	MI				$100,000	6/1/2009	138	12.5	C
B>C	East	METC	1448	Simpson	Install a distribution transformer at Simpson	MI				$2,200,000	6/1/2010	138	12.5	C

MTEP07 Appendix C - Project Table - 10/04/07 *Project Information from Facility Table*

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C	East	MISO/FE	1383	Richland area upgrades (ITC imports)	Reconductoring and terminal upgrades on Richland - Naomi and Richland - Ridgville 138 kV line in FE area	OH				$5,000,000	6/1/2009	138		C
C	East	NIPS	1551	Flint Lake to Tower Road - 2nd circuit	Add a 2nd 138kV circuit between Flint Lake and Tower Road	IN				$2,688,000	5/1/2008	138		C
C	East	WPSC	1214	Garfield - Grawn Line Rebuild	Line Rebuild to 795ACSR for future 138KV operation	MI				$1,700,000	8/1/2008	69		C
C	East	WPSC	1216	Garfield - Hall Street Line Re-rate	Rerate line to 75C	MI				$150,000	8/1/2008	69		C
C	East	WPSC	1220	Copemish - Bass Lake Line Rerate	Rerate line to 75C	MI				$1,200,000	8/1/2009	69		C
C	East	WPSC	1587	Gaylord to Advance to Oden Build 138kV Circuit	Build New 138 kV line	MI				$14,022,000	7/1/2010	138		C
C	East	WPSC	1631	Allendale to Osipoff Rebuild	Rebuild Overloaded Line	MI				$4,359,000	8/1/2013	69		C
C	East	WPSC	1632	Potter to East Bay Rerate	Rerate Overloaded Line	MI				$648,000	8/1/2013	69		C
C	West	XEL	1378	West St. Cloud - Granite City 115 Reconductor	West St. Cloud - Granite City 115 Reconductor	MN					6/1/2011	115		C
C	West	XEL	1547	Ironwood bus upgrade	Replace the Ironwood 115 kV equipment with ratings below 450 Amps with 850 Amp equipment (or next standard size). This should inclue the following: 200 Amp CT, 300 Amp wave trap, 380 Amp Bus, 400 Amp Breaker CT	WI				$450,000	6/1/2008	115		C
C	West	XEL	1548	La Crosse Capacitor banks	Install one 60 MVAR capacitor bank on 161 kV Bus 1 at La Crosse Substation and a second 60 MVAR capacitor bank on the 161 kV bus at Monroe County Substation.	WI				$2,300,000	6/1/2009	161	69	C
C	West	XEL	1549	Eau Claire - Hydro Lane 161 kV Conversion	1.)Install 161 kV circuit breaker at Eau Claire Substation.2.)Cut	WI				$20,602,000	6/1/2011	161	69	C
C	West	XEL/GRE	1380	Scott County - West Waconia 115	Scott County - West Waconia 1 115	MN					5/1/2010	115		C
Projects with In Service Dates after Plan Year											1/1/2014			C
C	West	ATC LLC	1452	Cornell - Range Line 138 kV line upgrade	Cornell - Range Line 138 kV line upgrade	WI				$6,000,000	6/1/2014	138		C
C	West	ATC LLC	1623	Montrose Capacitor Banks	Install two 16.33 MVAR 69kV capacitor banks at Montrose substation	WI					6/1/2014	69		C
C	West	ATC LLC	1625	North Randoph Transformer	Install a 500 MVA 345/138 kV transformer at the North Randolph 138 kv SS by looping in the Columbia-South Fond du Lac 345-kV line	WI					6/1/2014	345	138	C
C	West	ATC LLC	1629	Femrite 69-kV Capacitor Banks	Install two 16.33 MVAR 69kV capacitor banks at Femrite substation	WI					6/1/2014	69		C
C	West	ATC LLC	1630	Femrite 138-kV Capacitor Banks	Install two 24.5 MVAR 138kV capacitor banks at Femrite substation	WI					6/1/2014	138		C
C	East	METC	1225	Thompson Rd-Tallman 138 kV	Thompson Road - Tallman 138 kV line	MI				$5,000,000	5/1/2015	138		C
C	West	ATC LLC	1627	Uprate Bain-Albers 138-kV line	Increase clearance of the Bain-Albers 138-kV line	WI					6/1/2015	138		C
C	Central	DEM	1571	Rockville (IPL) to Avon East new 138KV line	Construct 4.3 miles / 954ACSR of 138kv line from IPL Rockville to Avon East	IN				$2,980,000	6/1/2015	138		C
C	West	XEL	1379	Pulaski - Linn Street - Becker - Liberty 69 kV to 115 kV upgrade	Pulaski - Linn Street - Becker 69 kV to 115 kV upgrade	MN					6/1/2015	115		C
C	West	MDU	1355	Heskett - Additional 230/115 kV Switchyard and 115 kV Capacitor	Heskett - Additional 230/115 kV Switchyard 230 115 Switchyard in parallel w/ existing Heskett switchyard	ND					11/1/2015	230	115	C

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C	West	DPC/XEL	1559	Belvidere Projects & La Crosse area upgrades	Belvidere-Wabaco 161 line, Belvidere-Marshland 161 line, Alma-Belvidere 161 kV lines 1 and 2, Belvidere 345/161 kV transformers	WI	MN			$42,120,000	12/15/2015	345	161	C
C	West	ATC LLC	575	Pulliam-New Suamico conversion to 138 kV for T-D interconnection	Rebuild/Convert Pulliam-New Suamico 69 kV line to 138 kV	WI				$6,221,325	6/1/2016	138		C
C	East	ITC/METC	1382	Michigan 765 kV Backbone	Project constructs a 765 kV circuit from AEP's Cook station to a new 765 kV station at the Kenowa 345 kV (METC) station including one 765/345 kV transformer at Kenowa. A new 765 kV circuit from the Kenowa station to a new 765 kV station at the Denver location including a 765/138 kV transformer. A new 765 kV circuit from the Denver station to a new 765 kV station at the Sprague Creek location including a 765/345 kV transformer at Sprague Creek. A new 765 kV circuit from the Sprague Creek station to a new 765 kV station at the Bridgewater site including two 765/345 kV transformers. A new 765 kV circuit from Bridgewater to a new 765 kV station near the Indiana - Ohio border tapping the Dumont to Marysville 765 kV circuit. A new 765 kV circuit from the Bridgewater station to AEP's South Canton 765 kV station.	MI				$2,500,000,000	12/31/2016	765	138	C
C	East	METC	649	Argenta - Palisades(Sag) 345 ckt # 1&2	Argenta - Palisades(Sag) 345 ckt # 1&2	MI				$500,000	5/1/2017	345		C
C	East	METC	650	Battle Creek - Morrow 138 ckt # 1	Rebuild Battle Creek-Morrow 138 kV line 14.4 miles to 795 ACSS	MI				$3,400,000	5/1/2017	138		C
C	East	METC	662	Weeds Lake 345/138 kV Station	Construct new 345/138 kV single transformer station	MI				$13,000,000	5/1/2017	345	138	C
B>C	East	METC	480	Brickyard - Felch 138 kV line	Rebuild 12.8 miles to 795 ACSS	MI				$3,000,000	6/1/2017	138		C
B>C	East	METC	642	Argenta - Hazelwood(Sag) 138 ckt # 1	Argenta - Hazelwood(Sag) 138 ckt # 1	MI		Other	Excluded	$50,000	6/1/2017	138		C
B>C	East	METC	646	Edenville - Warren 138 ckt # 1	Rebuild Edenville-Warren 138 kV line 14.75 miles to 795 ACSS	MI				$4,000,000	6/1/2017	138		C
C	East	METC	1430	Buck Creek switching station	Convert 138/46kV substation to a switching station by installing 3 high side 138kV breakers at Buck Creek	MI				$4,500,000	6/1/2017	138		C
C	East	METC	1431	Vergennes-Kendrick-Plaster Creek 138kV line	Build new 16mile 138kV line from Vergennes to Kendrick and puchase Kendrick-Plaster Creek spur	MI				$14,000,000	6/1/2017	138		C
C	East	METC	1432	Withey Lake-Twining 138kV line	Rebuild 0.2 miles of Withey Lake-Twining 138kV line	MI				$100,000	6/1/2017	138		C
B>C	East	METC	651	Stover - Clearwater 138 kV Line (Phase 2)	Rebuild Stover - Clearwater 138 kV line 8.8 miles to 795 ACSS	MI				$2,800,000	5/1/2018	138		C
C	East	METC	1429	Barry-Thompson Rd 138kV line	Build new 17mile 138kV line from Barry to Thompson Rd	MI				$20,000,000	6/1/2018	138		C
C	East	FE	1604	Bayshore-Ottawa-Toussaint 138kV 3-terminal line elimination	Eliminate Bayshore-Ottawa-Toussaint 138kV 3-terminal line. Install two 138kV breakers at Toussaint to create Bayshore-Toussaint and Ottawa-Toussaint 138kV 2-terminal lines.	OH				$500,000		138		C

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C		**Appendix C**																		C
C	West	ALTW	1354	3292	12/31/2010	Heron Lake	Storden	1	161		440	Rebuild line to higher capacity	MN			Proposed				C
A>C	Central	Ameren	143	56	6/1/2011	Cahokia	N. Coulterville	1	230		400	increase ground clearance	IL	45.0		Proposed	$644,600			C
C	Central	Ameren	1237	1936	6/1/2010	Campbell	Euclid-Page	1	138		415	Rebuild dbl. ckt. 138 kV	MO	5.3		Proposed	$15,254,100			C
C	Central	Ameren	1238	1937	6/1/2010	GM-Point Prairie 161 kV Lin	AECI Enon Substation	1	161		280	Extend 1 mile of line to AECI Enon Substation	MO		1.0	Proposed	$1,279,700			C
C	Central	Ameren	1240	1939	12/1/2010	Sioux	Huster	1	138		370	Reconductor 15 miles	MO	15.0		Proposed	$2,498,000			C
C	Central	Ameren	1240	1940	12/1/2010	Sioux	Huster	3	138		370	Reconductor 13 miles	MO	13.0		Proposed	$2,498,000			C
C	Central	Ameren	1530	2606	6/1/2010	Gibson City, South	Brokaw	1	138		337	Reconductor to 1600 A Summer Emergency	IL	28.5		Proposed	$14,853,044			C
C	Central	Ameren	1530	2607	6/1/2010	Gibson City, South	Paxton, East	1	138		337	Reconductor to 1600 A Summer Emergency	IL	15.9		Proposed	$8,291,040			C
C	Central	Ameren	1538	2615	6/1/2011	Pana, North	Ramsey, East	1	138		240	Rebuild line for operation at 120 degrees C	IL	18.4		Proposed	$2,702,200			C
C	Central	Ameren	1539	2616	6/1/2011	Roxford	Stallings	1	345		1195	Install PCB at Roxford Substation	IL			Proposed				C
C	Central	AmerenIP	737	1430	6/1/2009	Bluff City	W. Salem		138			new 138 kV breaker addition at Bluff City	IL			Proposed	$1,756,400			C
C	Central	AmerenIP	872	848	6/1/2008	Mahomet	Champaign	1	138		240	Reconductor 1.55 mile 477 kcmil ACSR from Maho	IL	1.6		Proposed	$725,500			C
C	Central	AmerenIP	1529	2605	6/1/2010	Brokaw	State Farm Line 1596	1	138		415	Reconductor to 2000 A Summer Emergency	IL	3.2		Planned	$2,566,900			C
C	Central	AmerenIP	1536	2613	6/1/2011	Latham	Mason City	1	138		240	Reconductor Latham Tap-Kickapoo Tap	IL	15.8		Proposed				C
C	Central	AmerenIP	1540	2617	6/1/2011	Sidney	Windsor	1	138		321	Reconductor to 1600 A Summer Emergency	IL	13.1		Proposed				C
C	West	ATC LLC	1450	1453	6/1/2008	Cornell (4.5 ohm reactor)	Fiebrantz		138				WI			Proposed	$4,651,493			C
C	West	ATC LLC	1555	3103	6/1/2009	Perkins	Capacitor banks		138		2x16.33 MVAR		MI			Planned	$1,395,185			C
C	West	ATC LLC	1621	3239	6/1/2013	Birchwood	Lake Delton	1	138		383/478	Build a new line between Birchwood & Lake Delton	WI	5.0		Proposed				C
C	West	ATC LLC	1626	3245	6/1/2010	Summit	Capacitor banks		138		2x34.2 MVAR		WI			Proposed				C
C	West	ATC LLC	1628	3253	6/1/2013	Columbia T22 345-138 kV	Transformer	2	345	138	527/574	Replace Columbia T22 345/138-kV Transformer	WI			Proposed				C
B>C	Central	DEM	625	1301	6/1/2008	Pierce/Beckjord 345/138 kV	transformer	C	345	138	172	Add third 345/138kV xfr 400 MVA connected to Be	OH			Planned	$2,527,029			C
B>C	Central	DEM	625	2568	6/1/2008	Pierce	Beckjord		138		500	Install new 138kV cir with a capacity approx 500MV	OH			Planned	$132,486			C
C	Central	DEM	841	820	6/1/2013	Westwood Bk1	transformer	1	345	138	412.9	Replace 1200A 138kV equipment with 2000A to al	IN			Planned	$554,000			C
C	Central	DEM	1512	2588	6/1/2010	Ashland	Rochelle		138			Install underground 138 kV circuit from Ashland to	OH		1.6	Proposed	$2,478,513			C
C	Central	DEM	1560	3111	6/1/2010	Edwardsport	capacitor		138		57.6 MVAR	Install a 138kV 57.6MVAR capacitor at Edwardspo	IN			Planned	$500,000			C
C	Central	DEM	1561	3112	6/1/2011	Kokomo Webster St (termin	New London	1	230		797	Retire existing 1600A circuit switcher and complete	IN			Planned	$399,580			C
C	Central	DEM	1565	3117	12/31/2013	Carlisle	Hutchings (DP&L)	1	138		374	Convert existing 187 MVA - 69 KV line (DP&L - F6	OH	2.6		Proposed	$2,315,946			C
B>C	East	FE	1317	2187	6/1/2009	Hayes	Hayes	1	345	138	444/466 MVA	New Hayes Transformer	OH			Proposed	$1,600,000			C
B>C	East	FE	1317	2188	6/1/2009	Hayes	Hayes		345	138		New Hayes Substation	OH			Proposed	$9,400,000			C
C	East	FE	1383	2385	6/1/2009	Richland 138 kV	Ridgeville Jct 138 kV	1	138		208	Reconductor 12 mile portion of double circuit tower	OH	12.0		Proposed	$3,500,000			C
C	East	FE	1383	2386	6/1/2009	Richland 138 kV	Naomi Jct 138 kV	1	138		208	Reconductor one of two circuits on a 10 mile stretc	OH	10.0		Proposed	$1,500,000			C
C	East	FE	1596	2679	6/1/2008	Lakeview Substation	Capacitor Bank		138			Capacitor Bank Addition	OH			Planned	$806,357			C
C	East	FE	1597	2680	6/1/2010	Galion 138kV	Capacitor Bank		138			Capacitor Bank Addition	OH			Proposed	$1,645,789			C
C	East	FE	1600	2687	6/1/2011	Beaver	Wellington	1	138		161/194 MVA	New Line	OH	23.0		Proposed	$5,020,000			C
C	East	FE	1601	2688	6/1/2009	Chamberlin	Shalersville	1	138		260/309 MVA	New Line	OH	12.0		Planned	$3,150,273			C
C	East	FE	1603	2669	6/1/2012	East Springfield	London	2	138			New Line			15.5	Planned	$12,914,379			C
C	East	FE	1603	2670	6/1/2012	London	Darby	1	138					20.6		Planned				C
C	East	FE	1603	2671	6/1/2012	Darby	Tangy	1	138					18.0		Planned				C
C	East	FE	1606	2698	6/1/2009	Barberton	South Akron	1	138		192/229 MVA	New Line	OH	8.1		Planned	$3,489,106			C
C	East	FE	1607	2699	6/1/2010	Existing Chamberlain-Mansf	[Cut and Looped into] Hanna	1	345		1504/1793 MVA	New Line tapping existing line	OH	2.0		Planned	$4,940,700			C
C	East	FE	1609	2701	6/1/2009	Tangy	Substation	5	345	138	382/473 MVA	New 345/138 kV Transformer	OH			Planned	$7,305,325			C
C>B	East	FE	1610	2702	6/1/2009	Avon	Substation	92	345	138	505/664 MVA	New 345/138 kV Transformer	OH			Planned	$5,965,035			C
C	West	GRE	1018	640	6/1/2011	Little Falls	Pierz (operated 34 kV)	1	115		196	115 kv line operated at 34.5	MN	9.0		Proposed	$900,000			C
C	West	GRE	1354	2234	12/31/2010	Cobden	Dotson	1	69				MN		12.0	proposed				C
C	West	GRE	1354	2235	12/31/2010	Dotson	Storden	1	161		434		MN		29.0	proposed				C
C	West	GRE	1354	2236	12/31/2010	Dotson	West New Ulm	1	161		434		MN		25.0	proposed				C
C	West	GRE	1354	2237	12/31/2010	Dotson Substation		1	161	69	56		MN			proposed				C
C	West	GRE	1354	2238	12/31/2010	Dotson Substation		2	161	69	56		MN			proposed				C
C	West	GRE	1354	2239	12/31/2010	West New Ulm	transformer	1	161	115	448		MN			proposed				C
C	West	GRE	1354	3293	12/31/2010	Dotson	West New Ulm	1	161		440	New 161 kV line	MN			Proposed				C
B>C	East	ITC	694	1385	12/31/2009	Saratoga 345/120 kV	transformer		345	120			MI			Proposed	$1,100,000			C
B>C	East	ITC	694	1386	12/31/2009	Saratoga 120 kV	Robin 120 kV	1	120		444		MI	23.3	0.6	Proposed	$700,000			C
B>C	East	ITC	694	1387	12/31/2009	Saratoga 120 kV	Wabash 120 kV	1	120		299		MI	13.6	0.6	Proposed	$700,000			C

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B>C	East	ITC	694	1388	12/31/2009	Saratoga 120 kV	Bunce Creek 120 kV	1	120		313		MI	12.5	0.6	Proposed	$700,000			C
B>C	East	ITC	694	1389	12/31/2009	Saratoga 120 kV	Burns 2 120 kV	1	120		313		MI	17.7	0.6	Proposed	$700,000			C
B>C	East	ITC	694	1390	12/31/2009	Saratoga 345 kV	Greenwood 345 kV	1	345		2241		MI	13.4		Proposed	$600,000			C
B>C	East	ITC	694	1391	12/31/2009	Saratoga 345 kV	Greenwood 345 kV	2	345		2552		MI		13.4	Proposed	$13,500,000			C
B>C	East	ITC	694	1392	12/31/2009	Saratoga 345 kV	Pontiac 345 kV	1	345		1769		MI	42.9		Proposed	$600,000			C
B>C	East	ITC	694	1393	12/31/2009	Saratoga 345 kV	Belle River 345	1	345		2259		MI	16.5	4.2	Proposed	$6,000,000			C
B>C	East	ITC	694	1394	12/31/2009	Saratoga 345/120 kV	transformer	1	345	120	700		MI			Proposed	$5,000,000			C
C	East	ITC	902	919	12/31/2008	Greenwood 345/120 kV	transformer	2	345	120	700		MI			Proposed	$5,000,000			C
C	East	ITC	902	920	12/31/2008	Greenwood 120 kV	Wabash 120 kV	1	120				MI	10.9	11.8	Proposed	$4,000,000			C
C	East	ITC	902	921	12/31/2008	Greenwood 120 kV	Adams 120 kV	1	120		222		MI	15.7	12.7	Proposed	$3,000,000			C
B>C	East	ITC	903	922	12/31/2008	Bismark 230 kV	Stephens 230	1	230		657		MI		8.2	Proposed	$3,000,000			C
B>C	East	ITC	903	923	12/31/2008	Stephens 230/120 kV	Transformer	1	230	120	693		MI			Proposed	$4,000,000			C
B>C	East	ITC	903	924	12/31/2008	Stephens 120 kV	Redrun 120 kV	1	120		343		MI		5.4	Proposed	$2,000,000			C
B>C	East	ITC	908	934	5/30/2008	Lulu	Majestic	1	345		1195		MI	51.0		Proposed	$3,000,000			C
B>C	East	ITC	908	935	5/30/2008	Lulu	Milan	1	345		2241		MI	16.0		Proposed	$3,000,000			C
B>C	East	ITC	908	936	5/30/2008	Lulu	Monroe 3-4	1	345		2008		MI	15.0		Proposed	$3,000,000			C
B>C	East	ITC	908	937	5/30/2008	Lulu	Lemoyne	1	345		1536		MI	42.0		Proposed	$3,000,000			C
B>C	East	ITC	908	938	5/30/2008	Lulu	Allen Junction	1	345		1793		MI	19.0		Proposed	$3,000,000			C
B>C	East	ITC	908	1579	5/30/2008	Lulu	Monroe 1-2	1	345		2000		MI	12.1	3.0	Proposed	$4,500,000			C
B>C	East	ITC	908	1580	5/30/2008	Lemoyne	Monroe 3-4	1	345		2000		MI	33.1	3.0	Proposed	$4,500,000			C
C	East	ITC	909	939	5/30/2010	Atlanta Junct.	Hampton	1	345		1554		MI	16.0		Proposed	$500,000			C
C	East	ITC	909	940	5/30/2010	Atlanta Junct.	Thetford	1	345		1554		MI	22.0		Proposed	$500,000			C
C	East	ITC	909	941	5/30/2010	Atlanta Junct.	Atlanta 345	1	345		1553		MI		2.3	Proposed	$3,000,000			C
C	East	ITC	909	942	5/30/2010	Atlanta 345-230 kV	transformer	1	345	230	665		MI			Proposed	$5,000,000			C
C	East	ITC	909	943	5/30/2010	Atlanta 230	Tuscola 230	1	230		657		MI		13.6	Proposed	$13,500,000			C
C	East	ITC	909	944	5/30/2010	Tuscola 230-120 kV	transformer	1	230	120	557		MI			Proposed	$5,000,000			C
C	East	ITC	909	945	5/30/2010	Tuscola 230	Hunters Creek 230	1	230		657		MI		22.5	Proposed	$500,000			C
C	East	ITC	909	946	5/30/2010	Hunters Creek 345	Blackfoot 345	1	345		2002		MI	20.0		Proposed	$5,000,000			C
C	East	ITC	909	947	5/30/2010	Hunters Creek 345	Belle River 345	1	345		2002		MI	45.0		Proposed	$5,000,000			C
C	East	ITC	909	948	5/30/2010	Hunters Creek 345-230 kV	transformer	1	345	230	665		MI			Proposed	$5,000,000			C
C	East	ITC	909	949	5/30/2010	Hunters Creek 230-120 kV	transformer	1	230	120	557		MI			Proposed	$5,000,000			C
B>C	East	ITC	1012	1582	5/30/2007	Wayne 120 kV	Newburg 120 kV	3	120	120	343		MI		2.8	Proposed	$1,200,000			C
B>C	East	ITC	1295	2124	6/30/2010	Quaker 120	Southfield 120	1	120		183/232	new line	MI		7.4	Proposed				C
C	East	ITC	1303	2135	5/31/2007	Arrowhead 120 kV	Bypass Switch		120			New N/O bypass switch	MI			Planned	$940,000			C
C	East	ITC	1550	2639	5/31/2008	Hager 120 kV	Sunset 120 kV	1	120		351	Transpose line entrance with the Sunset-Southfield	MI	0.1		Proposed				C
C	West	MDU	1355	2241	11/1/2009	Heskett	Capacitor		115		30 MVAr		ND			Planned				C
C	West	MDU	1356	2243	11/1/2009	Glenham	Reactors		230	115	30 MVAr	Control high voltage on WAPA Bismarck - Oahe 23	ND			Proposed				C
A>C	East	METC	240	336	6/1/2011	Garfiled	Hemphill	1	138		521		MI	9.2		Proposed	$1,900,000			C
A>C	East	METC	494	1317	12/1/2007	Battle Creek	Verona(Sag)	2	138				MI	1.0		Proposed	$50,000			C
B>C	East	METC	984	1547	6/1/2011	Denver Station	New Station		345			New Station	MI			Proposed	$77,132,000			C
B>C	East	METC	987	1550	6/1/2013	Emmet	Stover	1	138				MI			Proposed	$10,250,000			C
C	East	METC	1428	2431	5/1/2013	Roosevelt 345kV	345/138kV transformer		345	138		Add 345/138kV transformer along with two 345kV	MI			Proposed	$6,000,000			C
C	East	METC	1428	2432	5/1/2013	Roosevelt 138kV	Black River 138kV		138			Install new 3mile 795 ACSS 138kV line from Roos	MI			Proposed	$10,000,000			C
B>C	East	METC	1443	2447	6/1/2009	Milham 138kV	Upjohn 138kV	1	138	12.5		Install a second distribuiton transformer served fro	MI			Proposed	$100,000			C
B>C	East	METC	1448	2452	6/1/2010	Simpson 138kV			138	12.5		Install a second distribution transformer at Simpso	MI			Proposed	$2,200,000			C
C	East	NIPS	1551	2650	5/1/2008	Flint Lake	Tower Road	2	138		316	Add 2nd 138kV circuit	IN		5.5	Planned	$2,688,000			C
C	East	WPSC	1214	1909	8/1/2008	Garfield	Grawn		69		102.4 MVA	Rebuild Overloaded Line	MI	7.7		Proposed	$1,700,000			C
C	East	WPSC	1216	1911	8/1/2008	Garfield	Hall Street		69		41.2 MVA	Rerate Overloaded Line	MI	3.7		Proposed	$150,000			C
C	East	WPSC	1220	1915	8/1/2009	Copemish	Bass Lake		69		41.2 MVA	Rerate Overloaded Line	MI	28.9		Proposed	$1,200,000			C
C	East	WPSC	1587	3150	7/1/2010	Gaylord 138	Oden 138	1	138		396.1/514.9	Build new line	MI		46.7	Proposed	$14,022,000			C
C	East	WPSC	1631	3257	8/1/2013	Allendale	Osipoff	1	69			Rebuild Overloaded line	MI	14.5		Proposed	$4,359,000			C
C	East	WPSC	1632	3258	8/1/2013	Potter	East Bay	1	69			Rereate Overloaded line	MI	4.3		Proposed	$648,000			C
C	West	XEL	1354	3294	12/31/2010	West New Ulm	transformer	1	115	69	70		MN			Proposed				C
C	West	XEL	1378	2310	6/1/2011	West St. Cloud	Granite City	1	115		620	Reconductor	MN			Proposed				C

App ABC	Region	Reporting Source	PrjID	Facil ID	Expected ISD	From Sub	To Sub or Equipment	Ckt	High kV	Low kV	Ratings	Upgrade Description	State	Miles Upg	Miles New	Planning Status	Estimated Cost	C.S.	P.S.	M07 ABC
C	West	XEL	1547	2631	6/1/2008	Ironwood bus upgrade	terminal equipment		115		160	Replace capacity-limiting terminal equipment	WI			Planned	$450,000			C
C	West	XEL	1548	2632	6/1/2009	La Crosse	Capacitor Bank		161		60 MVAR	Install capacitor banks to maintain contingent volta	WI			Planned	$2,300,000			C
C	West	XEL	1548	3278	6/1/2009	Monroe County	Capacitor		161	69	2x30 MVAR		MN			Planned				C
C	West	XEL	1549	2635	6/1/2009	Wheaton	Eau Claire		161		335	Terminate Wheaton - Presto Tap 161 kV Line at Ea	WI			Planned	$1,065,000			C
C	West	XEL	1549	2638	6/1/2009	Wheaton	Eau Claire		161		434	Reconductor 4.3 Miles of 161 kV line with 795 ACS	WI	4.3		Planned	$645,000			C
C	West	XEL	1549	2636	6/1/2010	Wheaton Tap	Wheaton		161		335	Construct 2.2 miles of new 161 kV line, double-circ	WI		2.2	Planned	$2,902,000			C
C	West	XEL	1549	2637	6/1/2010	50th Avenue Substation			161	69	70	Construct 161/69 kV Substation with two 70 MVA t	WI			Planned	$10,700,000			C
C	West	XEL	1549	2633	1/1/2011	Eau Claire	Hallie		161		434	Rebuild 69 kV corridor to 161 kV, convert Hallie Su	WI	1.5		Planned	$2,425,000			C
C	West	XEL	1549	2634	6/1/2011	Hallie	50th Avenue		161		434	Rebuild 69 kV corridor to 161 kV, convert Hallie Su	WI	2.5		Planned	$2,865,000			C
C	West	XEL/DPC/RPU/	1559	3275	12/15/2011	La Crosse	Genoa	1	161		400		WI	20.0		Proposed				C
C	West	XEL/GRE	1380	2314	5/1/2010	Scott County	West Waconia	1	115		310		MN		25.0	proposed				C
Projects after the Plan Year					1/1/2014															C
C	West	ATC LLC	1452	462	6/1/2014	Cornell	Range Line	2	138		248	replace underground cable with larger MVA	WI	2.4		Proposed	$6,000,000			C
C	West	ATC LLC	1623	3240	6/1/2014	Montrose	Capacitor banks		69		2x16.33 MVAR	Add caps to a New SS to be tapped into Y-42 betw	WI			Proposed				C
C	West	ATC LLC	1625	3242	6/1/2014	North Randolph	Transformer	1	345	138	500/500	Install a 500 MVA 345/138 kV transformer at the N	WI			Proposed				C
C	West	ATC LLC	1625	3243	6/1/2014	North Randolph	Columbia	1	345		1096/1096	Tap Columbia-South Fond du Lac into North Rand	WI			Proposed				C
C	West	ATC LLC	1625	3244	6/1/2014	North Randolph	South Fond du Lac	1	345		1096/1096	Tap Columbia-South Fond du Lac into North Rand	WI			Proposed				C
C	West	ATC LLC	1629	3254	6/1/2014	Femrite	Capacitor banks		69		2x16.33 MVAR		WI			Proposed				C
C	West	ATC LLC	1630	3255	6/1/2014	Femrite	Capacitor banks		138		2x24.5 MVAR		WI			Proposed				C
C	East	METC	1225	1925	5/1/2015	Thompson Road	Tallman	1	138				MI	19.2		Proposed	$5,000,000			C
C	West	XEL	1379	2311	6/1/2015	Pulaski	Linn Street	1	115		310	Upgrade from 69 kV to 115 kV	MN			Proposed				C
C	West	XEL	1379	2312	6/1/2015	Linn Street	Becker	1	115		310	Upgrade from 69 kV to 115 kV	MN			Proposed				C
C	West	XEL	1379	2313	6/1/2015	Becker	Liberty	1	115		310	Upgrade from 69 kV to 115 kV	MN			Proposed				C
C	Central	DEM	1571	3123	6/1/2015	IPL Rockville	Avon East	1	138		306	Construct 4.3 miles / 954ACSR of 138kv line from	IN		4.3	Proposed	$2,980,000			C
C	West	ATC LLC	1627	3252	6/1/2015	Bain	Albers	1	138		343/343	'Increase clearance of the Bain-Albers 138-kV line	WI			Proposed				C
C	West	MDU	1355	2242	11/1/2015	Heskett	Additional 230/115 kV Switchyard		230	115	200 MVA	Switchyard in parallel w/ existing Heskett switchyai	ND			Proposed				C
C	West	XEL/DPC	1559	2645	12/15/2015	Belvidere	Wabaco	1	161		400	new line	MN/WI		16.0	Proposed	$17,280,000			C
C	West	XEL/DPC	1559	2646	12/15/2015	Belvidere	Marshland	1	161		400	new line	MN/WI		23.0	Proposed	$24,840,000			C
C	West	XEL/DPC	1559	2644	12/15/2015	Alma	Belvidere	2	161		400		WI	1.0		Proposed				C
C	West	XEL/DPC	1559	2648	12/15/2015	Belvidere	transformer	1	345	161	448		MN			Proposed				C
C	West	XEL/DPC/RPU/	1559	2643	12/15/2015	Alma	Belvidere	1	161		400		WI	1.0		Proposed				C
C	West	XEL/DPC/RPU/	1559	3270	12/15/2015	Belvidere	transformer	1	345	161	448		MN			Proposed				C
C	West	XEL/DPC/RPU/	1559	3273	12/15/2015	Belvidere	North La Crosse	1	161		400		WI		40.0	Proposed				C
C	West	ATC LLC	575	1270	6/1/2016	Pulliam (now Bayport)	Suamico	1	138				WI			Proposed	$3,199,539			C
C	West	ATC LLC	575	1271	6/1/2016	Suamico	Sobieski	1	138				WI			Proposed	$1,510,893			C
C	West	ATC LLC	575	1272	6/1/2016	Sobieski	Pioneer	1	138				WI			Proposed	$1,510,893			C
C	East	ITC/METC	1382	2367	12/31/2016	Cook 765 kV	Kenowa 765 kV	1	765		4465	100 miles of new 765 kV line and new 765 kV Ken	MI		100.0	Proposed	$400,000,000			C
C	East	ITC/METC	1382	2368	12/31/2016	Kenowa 765 kV	Denver 765	1	765		4465	30 miles of new 765 kV line and new 765 kV Denv	MI		30.0	Proposed	$150,000,000			C
C	East	ITC/METC	1382	2369	12/31/2016	Sprague Creek 765 kV	Denver 765 kV	1	765		4465	100 miles of new 765 kV line and new 765 kV Spra	MI		100.0	Proposed	$400,000,000			C
C	East	ITC/METC	1382	2370	12/31/2016	Sprague Creek 765 kV	Bridgewater 765 kV	1	765		4465	50 miles of new 765 kV line and new 765 kV Bridg	MI		50.0	Proposed	$225,000,000			C
C	East	ITC/METC	1382	2371	12/31/2016	Bridgewater 765 kV	Site A 765 kV	1	765		4465	135 miles of new 765 kV line and new 765 kV Site	IN/OH		135.0	Proposed	$530,000,000			C
C	East	ITC/METC	1382	2372	12/31/2016	Site A 765 kV	Dumont 765 kV	1	765		4465	Taps Current Marysville-Dumont 765 kV line	IN/OH			Proposed	$10,000,000			C
C	East	ITC/METC	1382	2373	12/31/2016	Site A 765 kV	Marysville 765 kV	1	765		4465	Taps Current Marysville-Dumont 765 kV line	IN/OH			Proposed	$10,000,000			C
C	East	ITC/METC	1382	2374	12/31/2016	Bridgewater 765 kV	South Canton 765 kV	1	765		4465	170 miles of new 765 kV line	MI/OH		170.0	Proposed	$600,000,000			C
C	East	ITC/METC	1382	2375	12/31/2016	Bridgewater 345 kV	Majestic 345 kV	1	345		1828	Taps the majestic end of the Allen Junction-Maj-M	MI			Proposed	$10,000,000			C
C	East	ITC/METC	1382	2376	12/31/2016	Bridgewater 345 kV	Majestic 345 kV	2	345		1828	Taps the Majestic-Milan 345 kV Circuit	MI			Proposed	$10,000,000			C
C	East	ITC/METC	1382	2377	12/31/2016	Bridgewater 345 kV	Milan 345 kV	1	345		1828	Taps the Majestic-Milan 345 kV Circuit	MI			Proposed	$10,000,000			C
C	East	ITC/METC	1382	2378	12/31/2016	Sprague Creek 345 kV	Blackfoot 345 kV	1	345		795	Taps the Blackfoot-Madrid 345 kV Circuit	MI			Proposed	$10,000,000			C
C	East	ITC/METC	1382	2379	12/31/2016	Sprague Creek 345 kV	Madrid 345 kV	1	345		795	Taps the Blackfoot-Madrid 345 kV Circuit	MI			Proposed	$10,000,000			C
C	East	ITC/METC	1382	2380	12/31/2016	Kenowa 765/354 kV	transformer	1	765	345	3040	New 765/345 kV Xfmr at Kenowa	MI			Proposed	$25,000,000			C
C	East	ITC/METC	1382	2381	12/31/2016	Denver 765/138 kV	transformer	1	765	138	1119	New 765/138 kV Xfmr at Denver	MI			Proposed	$25,000,000			C
C	East	ITC/METC	1382	2382	12/31/2016	Sprague Creek 765/345 kV	transformer	1	765	345	3040	New 765/345 kV Xfmr at Sprague Creek	MI			Proposed	$25,000,000			C
C	East	ITC/METC	1382	2383	12/31/2016	Bridgewater 765/345 kV	transformer	1	765	345	3040	New 765/345 kV Xfmr at Bridgewater	MI			Proposed	$25,000,000			C
C	East	ITC/METC	1382	2384	12/31/2016	Bridgewater 765/345 kV	transformer	2	765	345	3040	New 765/345 kV Xfmr at Bridgewater	MI			Proposed	$25,000,000			C

MTEP07 Appendix C - Facility Table - 10/04/07

App ABC	Region	Reporting Source	PrjID	Facil ID	Expected ISD	From Sub	To Sub or Equipment	Ckt	High kV	Low kV	Ratings	Upgrade Description	State	Miles Upg	Miles New	Planning Status	Estimated Cost	C.S.	P.S.	M07 ABC
C	East	METC	649	1334	5/1/2017	Argenta	Palisades(Sag)	1&2	345			conductor sag	MI	0.1		Proposed	$500,000			C
C	East	METC	650	1335	5/1/2017	Battle Creek	Morrow	1	138				MI	14.4		Proposed	$3,400,000			C
C	East	METC	662	1350	5/1/2017	Weeds Lake 345	Weeds Lake 138	1	345	138			MI		10.0	Proposed	$13,000,000			C
B>C	East	METC	480	1336	6/1/2017	Brickyard J	Felch Road	1	138				MI	12.8		Proposed	$3,000,000			C
B>C	East	METC	642	1325	6/1/2017	Argenta	Hazelwood(Sag)	1	138			conductor sag	MI	0.1		Proposed	$50,000			C
B>C	East	METC	646	1329	6/1/2017	Edenville J.	Warren	1	138				MI	14.8		Proposed	$4,000,000			C
C	East	METC	1430	2434	6/1/2017	Buck Creek 138kV	138kV Breakers		138			Convert 138/46kV substation to a switching station	MI			Proposed	$4,500,000			C
C	East	METC	1431	2435	6/1/2017	Vergennes 138kV	Kendrick 138kV		138			Build new 16mile 138kV line from Vergennes to Ke	MI			Proposed	$14,000,000			C
C	East	METC	1432	2436	6/1/2017	Withey Lake 138kV	Twining 138kV		138			Rebuild 0.2 miles of Withey Lake-Twining 138kV li	MI			Proposed	$100,000			C
B>C	East	METC	651	1337	5/1/2018	Stover	Clearwater	1	138				MI	8.8		Proposed	$2,800,000			C
C	East	METC	1429	2433	6/1/2018	Barry 138kV	Thompson Road 138kV		138			Build new 17mile 138kV line from Barry to Thomps	MI			Proposed	$20,000,000			C
C	East	FE	1604	2710		Toussaint	Bayshore/Ottawa		138			Install two 138 kV breakers at Toussaint	OH			Proposed	$500,000			C

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