**September 2011 10-Year Assessment**
**www.atc10yearplan.com**

## 2011 10-Year Assessment Executive Summary

While reliably meeting the needs of electricity customers is the top priority for any transmission owner, public policy initiatives are playing a major role in how utilities plan for their system needs. Traditionally, transmission owners performed planning studies and analysis for their individual needs; today, however, while local reliability remains the responsibility of the owner, the trend is toward broader-based planning driven by regional transmission organizations and government agencies. These broader plans improve access to markets and may help meet public policy requirements.

Changing the way transmission system costs are allocated also affects the planning as well as permitting for system improvements. Regional planning initiatives increasingly focus on projects that provide additional benefits beyond local-area reliability. These multi-benefit, or Multi-Value Projects (as defined by MISO), also include economic savings and the ability to move renewable energy from where it is generated to where it can be used. As these projects are identified, regulators from multiple states will need to work together to determine cost sharing as well as permitting. We are working diligently with all stakeholders to design an incremental regional build-out of these projects to move forward efficiently and cost-effectively.

Three 345-kilovolt projects that MISO is considering for Multi-Value Project cost sharing were presented in the 2010 10-Year Assessment. These projects are the Badger Coulee, Dubuque-Spring Green-Cardinal and Pleasant Prairie (Bain)-Zion Energy Center projects. For an update on those projects, visit our website, www.atc-projects.com

Enforceable, mandatory reliability standards, developed by the North American Electric Reliability Corp. and approved by the Federal Energy Regulatory Commission in 2007, also play a role in how we plan, operate and maintain our system. Earlier this year, NERC issued a set of high-priority reliability issues to help the industry focus on standards setting, compliance, training and education. Several of those priorities, including a changing resource mix and the integration of new technologies, will impact the way we plan and operate our system.

Our planning process also is affected by pending Environmental Protection Agency regulations for electric generators and the recently issued FERC Order 1000 governing regional planning, public policy requirements and cost allocation. These issues, along with the internal identification of a new credible contingency scenario, have caused us to undertake a study on transmission reinforcements in northern Wisconsin and the Upper Peninsula. Later this year, we expect to identify a Northern Plan, some preliminary packages of projects that coordinate with the existing northeast Wisconsin and Upper Peninsula projects to address generation changes, load changes and developing transmission contingency concerns. As the EPA rules become clearer, additional studies may be undertaken to explore these need drivers in other areas of our service territory.

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The planning zone summaries included in this report detail specific projects identified to improve reliability and access to the market and renewable energy resources. A more comprehensive listing of these plans is available at our website www.atc10yearplan.com.

| Paul Jett<br>Director of Strategic Projects | Jeff Gillen<br>Director of System Planning | Mark Davis<br>Director of Asset Management |
|---|---|---|

**Capital cost**

The 2011 Assessment covers the years 2011 through 2020 and indicates a need for $3.8 to $4.4 billion in transmission system improvements. This total expenditure can be broken down into the following categories and includes future year inflation.

| Category | 2010 10-Year Capital Estimate (billions) | 2011 10-Year Capital Estimate (billions) |
|---|---|---|
| Specific Network Projects | $0.98 | $1.00 |
| Asset Maintenance | $0.70 | $0.99 |
| Generator Interconnections | $0.20 | $0.07 |
| Distribution Interconnections | $0.25 | $0.16 |
| Protection and Control | $0.11 | $0.10 |
| Unspecified Network Projects | $0.30 | $0.64/$1.24 |
| Other[1] | $0.13 | $0.13 |
| Subtotal | $2.67 | $3.09/$3.69 |
| Regional Multi-Benefits Projects | $0.75 | $0.72 |
| Total Expenditures | $3.42 | $3.81/$4.41 |

*[1] Other includes Administration & General, Asset Acquisition, Asset Contribution, and Infrastructure Relocation.*

The total cost trends of the last six assessments and updates are as follows:

| | Nov 2006 | Nov 2007 | Oct 2008 | Oct 2009 | Sept 2010 | Sept 2011 |
|---|---|---|---|---|---|---|
| **Specific Network Projects** | $1.7B | $1.4B | $1.3B | $1.0B | $1.0B | $1.0B |
| **Regional Multi-Benefits Projects** | $0.0B | $0.0B | $0.0B | $0.0B | $0.7B | $0.7B |
| **Asset Maintenance** | $0.3B | $0.4B | $0.5B | $0.7B | $0.7B | $1.0B |
| **Other Capital Categories** | $1.1B | $1.0B | $0.9B | $0.8B | $1.0B | $1.1B/$1.7B |
| | | | | | | |
| **Total 10-Year Capital Cost** | $3.1B | $2.8B | $2.7B | $2.5B | $3.4B | $3.8B/$4.4B |

Other Capital Categories can include developing or unspecified network projects, interconnection projects and infrastructure relocation.

In the 2011 Assessment, we project an increased total cost estimate for all transmission system improvements over a rolling 10-year period. Factors that can influence the total 10-year cost up or down as each future assessment is completed include:

- Addition of regional multi-benefits projects that provide local and regional reliability, economic and public policy benefits,
- Completion of prior projects,
- Changing load forecast,
- Changes in generation and distribution interconnection projects,
- Changes in mandatory reliability standards and regulatory policy,
- Additional projects that are driven by economic benefits, and
- Changing equipment and labor costs.

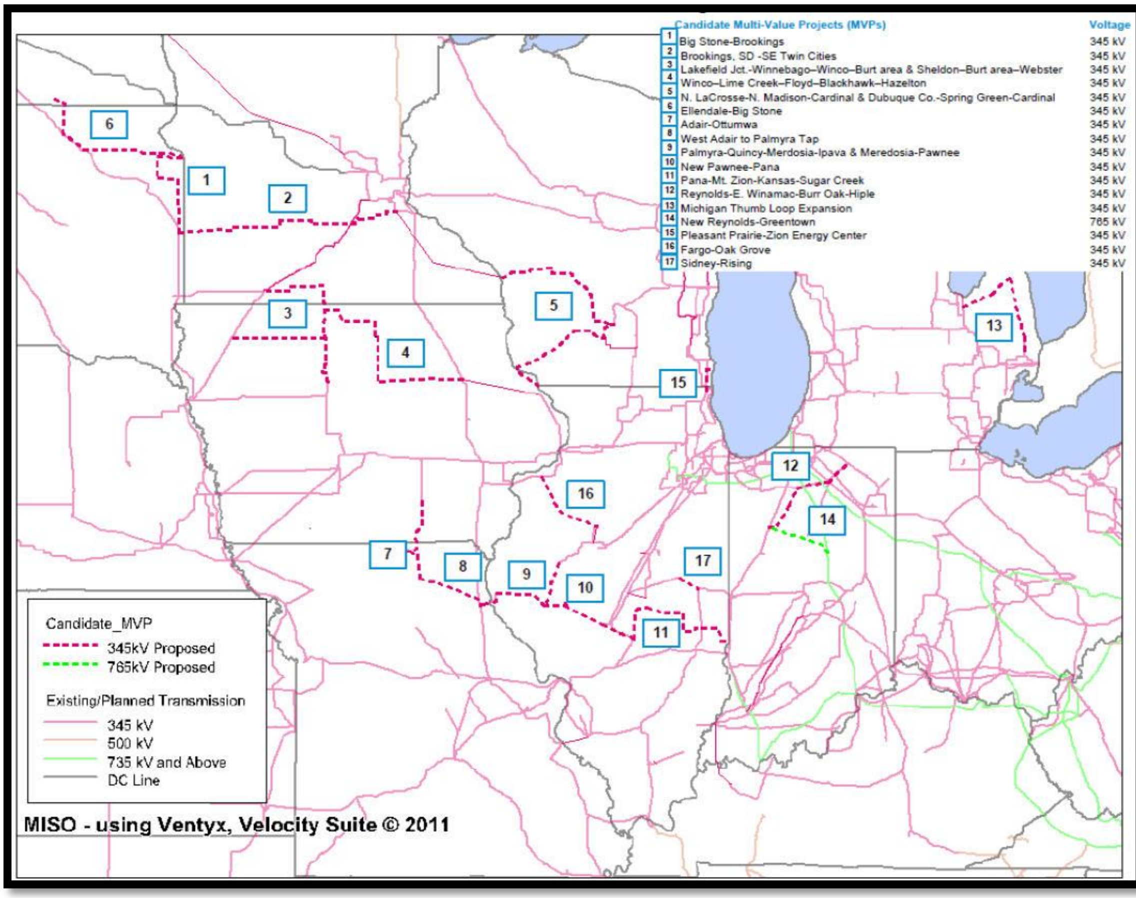
We use a capital forecast category called unspecified network projects to appropriately try to account for these various factors. The range of $640 million to $1,240 million represents anticipated costs from projects not specifically defined in the assessment, but potentially driven by some combination of the factors listed above. In particular for this assessment, we anticipate that additional congestion mitigation, higher levels of reliability requirements in the NERC transmission planning standards, and developing EPA rules will drive the need for more transmission. Considering variation due to all the factors, we estimate that the projected total 10-year capital cost above will likely range between $3.8 and $4.4 billion.

This report only reflects the estimated costs of the projects included in ATC's 10-year capital forecast. It does not address the responsibility of customer groups for the revenue requirements associated with the projects, or any cost sharing that would occur as a part of MISO's approved tariffs on cost allocation.

**Reliability for renewable energy: helping states meet their renewable goals**
**MTEP11 Candidate Multi-Value Project Study**

MISO was required by the Federal Energy Regulatory Commission to file a new cost-allocation methodology to address large regional projects. On July 15, 2010, MISO filed a new tariff for approval by the Federal Energy Regulatory Commission, which outlined a cost-allocation methodology for a new classification of project, Multi-Value Projects. FERC conditionally approved the methodology in December 2010. It allocates costs for Multi-Value Projects over the entire MISO footprint based on the percentage of energy used in each area. For our customers, the percentage that would be paid for MVPs across the MISO footprint is estimated between 10-15 percent.

This new methodology led the way to an MTEP11 Candidate MVP Study, which would allow MISO to study a portfolio of 17 projects for cost allocation. These 17 projects have been listed and mapped below:




Candidate MVP Portfolio map for MTEP11[1]

Our projects in this portfolio include Badger Coulee, Dubuque-Spring Green-Cardinal (#5 on the map) and Pleasant Prairie to Zion Energy Center (#15 on the map). MISO has put together a task team to complete this study and we are participating in the meetings and reviews. The models for this study were completed at the beginning of 2011 and the Regional Generation Outlet Study (RGOS) wind zones shown in the RGOS section of this report were used to determine future wind generation locations and capacities. The portfolio as a whole will be looked at to see that each project meets one of the three criteria for being designated an MVP project.

To learn more about the progress in the Candidate MVP Portfolio study please go to the following website:

https://www.midwestiso.org/Planning/Pages/MVPAnalysis.aspx

[1] This map is from the MISO homepage

## Regional, Multi-Value Projects

- ***Badger Coulee (formerly known as North La Crosse- North Madison-Cardinal) 345-kV project***

  In addition to MISO's evaluation of the Badger Coulee project and following approximately three years of study and analysis, we have determined that a 345-kilovolt transmission line from the La Crosse area to the greater Madison area would provide multiple benefits to the state of Wisconsin, including improved electric system reliability, economic savings for utilities and energy consumers, and access to additional renewable energy. As it finalizes its evaluation of the multiple benefits of the project, ATC will continue the public outreach efforts on the proposed Badger Coulee Transmission project in the 150-mile area from La Crosse to Madison to explore corridor options for the new line. If the Badger Coulee project is chosen as a Candidate Multi-Value Project under MISO's proposed cost-allocation methodology it would greatly reduce the cost of the line to our customers.

  ATC's studies indicate that the Badger Coulee Transmission Project is a multi-benefit project that would improve local and regional reliability, deliver economic savings to Wisconsin utilities and electric consumers and support renewable energy delivery. Preliminary analysis by ATC shows benefits over the 50-year book life of the project ranging from $230 million to $962 million. If the project is deemed a Multi-Value Project by MISO, preliminary studies show the project will more than cover the costs to ATC customers in all six futures studied. If the project is not deemed an MVP, the project will more than cover the costs in five of six futures studied.

  ATC currently expects to file an application to build the line with the Public Service Commission of Wisconsin in 2013. If approved by the PSC, construction on the new line would begin in 2015 to meet an in-service date of 2018. Transparency and stakeholder engagement have been hallmarks of our planning process from our company's inception. While planning studies for this project continue, we will continue to engage local officials and residents as well as other interested parties on the routing and siting issues. Because transmission line planning, siting and construction can take between five to 10 years, we want to ensure adequate time for public discussion and input.

  For more information or to be emailed updates, please visit www.BadgerCoulee.com

- ***Dubuque-Spring Green-Cardinal 345-kV project***

The Dubuque-Spring Green-Cardinal 345-kV project is also part of MISO's initial Candidate Multi-Value Project Portfolio and has been under study by ATC for the past three years. As part of the analysis discussed in the section on the Western Wisconsin Study, a 345-kV transmission line from Dubuque County to Spring Green to Cardinal was found to show benefits for Wisconsin. This line is approximately 104 miles long and has an expected in-service date of 2020. The combination of the Badger Coulee and the Dubuque-Spring Green-Cardinal 345-kV projects performed the best across all aspects of the reliability analyses. This combination provides additional benefits beyond any of the single 345-kV options and it provides the highest level of transfer capability for wind generation in Minnesota and Iowa. This combination also provided the most net economic benefits across most futures.

As with the Badger Coulee project, if this project is approved under the MVP cost-allocation method, the cost of this project to our customers would be greatly reduced.

*Renewable Investment Benefit*

Badger Coulee, Dubuque-Spring Green-Cardinal and the other projects in western Wisconsin will enable higher-capacity wind generation in Iowa, Minnesota, North Dakota and South Dakota to move more freely to loads to the east, including Wisconsin. Because renewable energy standards require a certain amount of energy (kWh) to be produced, there is the potential for significant capital cost savings if wind generation is built in higher wind capacity areas than in lower wind capacity areas. We have developed and tested with stakeholders and MISO a process for calculating the value of this benefit, and the dollar savings are included in the savings for both the Badger Coulee 345-kV line and the Dubuque-Spring Green-Cardinal 345-kV project, which are discussed in more detail in the Regional Planning section.

- ***Pleasant Prairie-Zion Energy Center 345-kV project***

Our final project included in MISO's MVP analysis is the Pleasant Prairie-Zion Energy Center 345-kV project. This is a 5.3 mile line connecting southeast Wisconsin with northeast Illinois. This project is proposed to provide additional reliability benefits and to relieve congestion around southern Lake Michigan, showing significant savings to customers in Wisconsin and Illinois in most futures studied. The results of the study were presented to stakeholders in January 2011, and we will file applications for this project in both Wisconsin and Illinois later this year. If approved, the in-service date for the project will be 2014.

More information can be found at the Pleasant Prairie – Zion Energy Center project webpage.

**Duke-American Transmission Co. (DATC)**

Building on more than 10 years of success, we are looking for opportunities to grow our company beyond our current service area in the Upper Midwest. In 2011, we formed a partnership with Duke Energy in a joint venture to build, own and operate new electric transmission infrastructure in North America. We believe Duke-American Transmission Co. is well-positioned to help address increasing demand for affordable, reliable transmission capacity in the United States and Canada. The DATC planning team, comprised of transmission planners from both companies, has been working to find and address the gaps in transmission that would provide additional economic, reliability, and public policy benefits to consumers. Thoughtful, well-designed transmission projects will afford customers, regulators and other stakeholders flexibility in determining which energy resources will help meet demand for electricity in the future. As such, they will serve as a springboard for next-generation energy technologies. For more information, please visit www.datcllc.com.

**Federal priorities**

In addition to creating reliability based standards, NERC has established a number of priorities for 2011. Integration of new technologies is one of the major priorities we are working on. We signed an agreement with the U.S. Dept. of Energy in 2010 for smart grid investment grants. A number of phasor measurement units have been installed on our system with a $1.3 million grant. This smart-grid technology is not yet fully realized, but it has helped us analyze the system in more detail during events. An additional $11.4 million grant is being used to extend fiber optic communication infrastructure. Both projects are on schedule.

Another NERC priority is to address a changing resource mix. Energy and environmental policies along with energy markets are driving proposals toward unprecedented changes in the resource mix of the bulk power system. We are currently studying potential system impacts and initial results are seeing reliability impacts that we must consider in the future.

Cyber security also is a NERC priority and under increasing scrutiny of FERC. We are participating in the NERC standards process to help anticipate the future impacts of these changes on our planning processes and systems.

***FERC Order 1000***

FERC recently issued an order that will have a significant impact on how transmission is planned and built in the U.S. The order impacts the way transmission is planned by requiring Regional Transmission Organizations to plan for public policy requirements such as Renewable Portfolio Standards and EPA regulations, and to coordinate their planning with their neighboring RTOs and other transmission providers. The order requires every RTO to have a regional cost-allocation method for regional and inter-regional projects. The order also opens the door to more competition in building regional, cost-shared transmission projects, although state and local laws regarding transmission construction are not affected.

**Planning for a reliable future**

Since publishing last year's assessment, we've energized additional components that provide reliability benefits to our customers.

- ❑ Expansion of the 345-kV switchyard at Oak Creek to interconnect the second of two new generators.
- ❑ Reconfiguration of the Kewaunee 345/138-kV switchyard and installation of a second 500 MVA 345/138-kV transformer.

***Transmission-Distribution interconnections***

Another aspect of reliability involves customers' distribution and/or generator interconnections. Several unanticipated large, end-use customer interconnections continue to develop within our service territory. Type, size and location of such interconnections have varied throughout the year. Many require an expedited response to determine if the system is equipped to support the unanticipated load.

Since publishing last year's assessment, we've energized two projects to interconnect new customers, including:

- ❑ Pleasant Valley Substation – A 138-kV bus at Pleasant Valley Substation in Washington County, Wis., was installed to allow a second distribution transformer interconnection.
- ❑ Warrens Substation – Construction was completed on a new 6.5-mile, 69-kV line that increases reliability and supports a new customer in Monroe County, Wis.

For more information, see T-D Interconnections.

***Generator interconnections***

Since last year's assessment was published, we interconnected the second Oak Creek (also known as Elm Road) unit (650 MW, net 615 MW). In addition, the generator interconnection projects identified for the modifications to the Point Beach Nuclear Plant are moving through our routing, siting and application process. Going forward, proposals for generation interconnection are for the most part focused on wind generation. As of July 1, 2011, 17 proposals to install more than 2,600 megawatts of wind turbines in Wisconsin are in the MISO generation queue.

The generator interconnection projects proposed for the Point Beach Nuclear Plant modifications will prepare the unit for years of continued reliable base load operation as well as provide a large amount of additional generating capacity. Our studies indicate that the additional output from these generating units and the substantial equipment modifications will result in transmission overloads and instability if the system in the area is not reinforced. More information on this project, the Barnhart-Branch River Electric Reliability project, can be found at our website: www.atc-projects.com

Generation uncertainties are growing due to proposed Environmental Protection Act regulations. We are working closely with generation owners and MISO to anticipate reliability impacts to our transmission system. In light of pending EPA regulations, we are reviewing the high-retirements scenario for the Upper Peninsula of Michigan in 2011 and its impact on northeast Wisconsin as well. In this review, we also are considering the reliability of the area due to a NERC Category 2 event dropping more than 400 megawatts of load on May 10, 2011. This event was caused by a single lightning strike affecting two lines on a common tower during the maintenance outage of another area line in off-peak load conditions. We are considering a guideline to define a new credible contingency suggested by this event and other similar events in the past. The generation uncertainties in ATC's footprint extend beyond the Upper Peninsula and could affect other generators in our footprint which may create additional reliability needs.

For more on generation developments in Wisconsin and Michigan's Upper Peninsula, see Generation Interconnections.

***Northern Plan***

Even with significant upgrades to transmission infrastructure in the Upper Peninsula in recent years, operational challenges remain due to the delicate balance that exists between generation, load, market flows and transmission.

ATC conducted an energy collaborative from 2008-2010 to determine the set of projects that would maintain the reliability of the electric system in the U.P. in the most cost-effective manner. Please refer to our U.P. Collaborative section for more details. Several projects are being implemented, including a back-to-back HVDC flow control device that will be installed near the Straits Substation in 2014. This innovative, $90 million project will enable the flows into and out of the U.P. to be controlled by MISO, maintaining appropriate thermal and voltage levels in both upper and lower Michigan. This project was approved by the MISO Board of Directors in June 2011 and will be cost-shared as a baseline reliability project. Combined with our smart-grid initiatives, this project will enhance our ability to operate reliably.

As noted in the generator interconnections section, we are studying the impacts that generation retirements and a new credible contingency type would have on transmission reinforcements in northeast Wisconsin as well as the Upper Peninsula. In the fall 2011, we expect to identify some preliminary packages of projects that work with the existing core Collaborative projects to continue to address generation change, load change, and new transmission contingency concerns in the northern portion of our system.

***Asset renewal***
While the top goal is always public and worker safety, two of the major objectives for our Asset Management Department are to minimize the total life-cycle cost and to manage the risk of aging infrastructure. Knowing and managing the costs and risks helps us identify the best-possible system improvements that serve multiple purposes and reduce overall cost. This year's assessment includes approximately $1 billion in asset renewal work, which includes maintenance and protection projects. Please refer to our Asset Renewal section for details.

One significant asset renewal project that is moving forward is the reconfiguration of the Pleasant Prairie switchyard to provide more reliability and operational flexibility.

**Our projects provide economic benefits and access**

The MISO Day 2 market, which ushered in the daily and hourly energy market in the Midwest, was first implemented in April 2005. Since that time, ATC has developed transmission to relieve market congestion where building the transmission saved ultimate ratepayers enough money to offset the cost of the transmission. The first major project approved on this basis was the Paddock-Rockdale project, which was placed in service in 2010.

*Improved access to market helps lower costs*
The infrastructure improvements we have made in the last 10 years have eased constraints on our system and allowed our customers access to lower-cost sources of electricity. We track wholesale electricity prices within our footprint and at three neighboring market hubs. When the Midwest market was established in 2005, the average locational marginal price within our footprint was $63.27 per megawatt hour, more than $10 higher than the average in our neighboring hubs. In 2010, the difference was only approximately $0.40 per mWh. This change is the result of many factors, including transmission additions and upgrades on our system.

We also evaluate the economic benefits of key reliability projects put in service each year. In 2010, ATC estimated that projects placed in service for reliability purposes saved ATC customers $46.8 million. This would equate to $801 million over the lifetime of the projects, compared to overall project costs of $304 million. This means that, even though these projects were built to provide a reliable system, they will more than pay for themselves through economic savings to ultimate customers.

***Economic benefit projects***

In addition to identifying reliability-based projects to address system needs, we are engaging stakeholders to identify the most important economic benefit projects. We are analyzing two economic projects in 2011: the Saratoga – Petenwell 138-kV line in western Wisconsin, and the Albers-Kenosha 138-kV line in southeast Wisconsin. Stakeholders specified three new futures that will be used to analyze these projects:

1. Aggressive energy efficiency future,
2. Cautious investment future and
3. Clean robust economy future.

Studies will be performed and results shared with stakeholders over the course of the year. In addition, customers and stakeholders who would like to request specific economic studies can do so if they are willing to pay for the studies and are willing to have the results posted publicly.

We also evaluate our reliability projects to determine if any of them have enough economic benefits to consider accelerating them. All projects have multiple benefits, and reliability projects often provide customers significant cost savings by providing access to lower-cost sources of power, either inside or outside of our service area. By screening reliability projects for economic benefits, one project (Project 18 from Table EP-1: Fairwater – Mackford Prairie plus Ripon – Metomen) was identified as having potential economic benefits and a candidate for acceleration of the in-service date. The accelerated in-service date is being pursued.

***South Lake Michigan Congestion Study***

The market congestion issues impacting southeast Wisconsin are part of a larger regional market congestion issue that extends south of Lake Michigan into Illinois and Indiana. We are working with MISO to identify short-, medium- and long-term fixes to the congestion issues. The Pleasant Prairie-Zion Energy Center 345-kV project is part of that solution. In addition, we identified three other, shorter-term projects that will help alleviate congestion:

- ❑ Uprate the Pleasant Prairie – Zion 345-kV line completed in 2011,
- ❑ Replace a 345-kV wave trap at Zion Substation completed in 2011, and
- ❑ upgrade terminal equipment at Butler and Tosa substations to allow Granville-Butler and Granville-Tosa 138-kV lines to operate at their full capability (2011/2012).

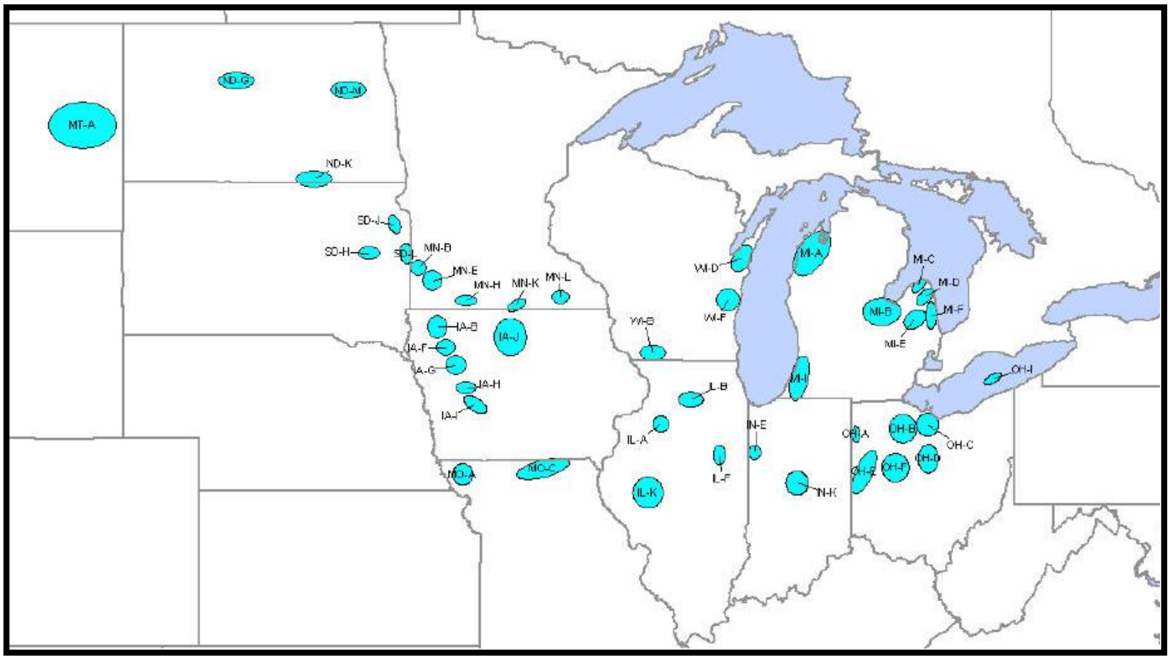
The economic planning process is described more thoroughly in the Economic Analysis section.

**Regional studies continue and expand**
In addition to providing updated need and project information, the 2011 Assessment presents information regarding our involvement in regional and inter-regional transmission system studies that support wind generation development. Please refer to Regional Planning for more information.

Developments in the Upper Midwest and the Eastern Interconnection could affect us and/or our customers. Among the more relevant of these include renewable portfolio standards, transmission initiatives being investigated by MISO and wind generation developments. The latest developments are summarized below.

- **MISO Regional Generation Outlet Study (RGOS)**
  MISO initiated the RGOS Phase I as a targeted planning study. The study was completed in 2009 and a report was issued in 2010. The report identified both 345-kV solutions, 765-kV solutions and combination solutions to facilitate the delivery of 28 to 34 GWs of wind capacity based on the Renewable Portfolio Standard requirements in four states - Illinois, Iowa, Minnesota and Wisconsin.

  RGOS Phase II considered the wind generation required to satisfy state RPSs and goals beyond those focused on in Phase I. The study examined three main scenarios with varying locations of wind generation in the MISO footprint, totaling approximately 40 GW of capacity. The wind zones that were modeled are shown below:




MISO developed three transmission designs to move the wind. One is a 345-kV design, which is entirely alternating current. One is a 765-kV design, which is also entirely AC and the third is a 345-kV design, which combines AC lines with high-voltage direct-current lines. Each design was evaluated for its ability to deliver wind generation while maintaining system reliability. They have also been evaluated economically to determine which design provides the most cost efficient dispatch of resources across MISO's footprint.

To learn more about the final economic portion of the study and the three overlays studied, please see the Final RGOS Report at the link below:

https://www.midwestiso.org/Library/Repository/Study/RGOS/Regional Generation Outlet Study.pdf

- ***SMARTransmission Study***
  We, along with co-sponsors Electric Transmission America, a transmission joint venture between subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., Exelon Corp., NorthWestern Energy, Xcel Energy, and MidAmerican Energy Co., a subsidiary of MidAmerican Energy Holdings Co., performed a comprehensive study of the transmission needed in the Upper Midwest to ensure reliability and support renewable energy development for transport to population and electricity load centers.

The study was completed in two phases, a reliability analysis phase and an economic analysis phase.

Phase 1 of the study evaluated the reliability of various alternatives designed to move 56.8 GW of wind generation capacity. The 56.8 GW of wind generation capacity generally reflects a federal Renewable Portfolio Standard requirement of 20 percent for all states in the SMART Study footprint. Adjustments were made for states with approved RPS requirements or goals in excess of 20 percent. At the conclusion of Phase 1, three alternatives were recommended for further study based on a rigorous reliability assessment and stakeholder input. One alternative is primarily 765-kV extra-high voltage transmission, another includes 765-kV combined with limited use of high-voltage direct-current transmission lines, while the third constitutes a combination of both 345-kV and 765-kV transmission lines.

The results of Phase 2, completed in 2010, indicate that two alternatives have substantially similar economic and environmental performance as well as abilities to reliably deliver wind generation. Both the Phase 1 and Phase 2 reports can be downloaded at www.smartstudy.biz.

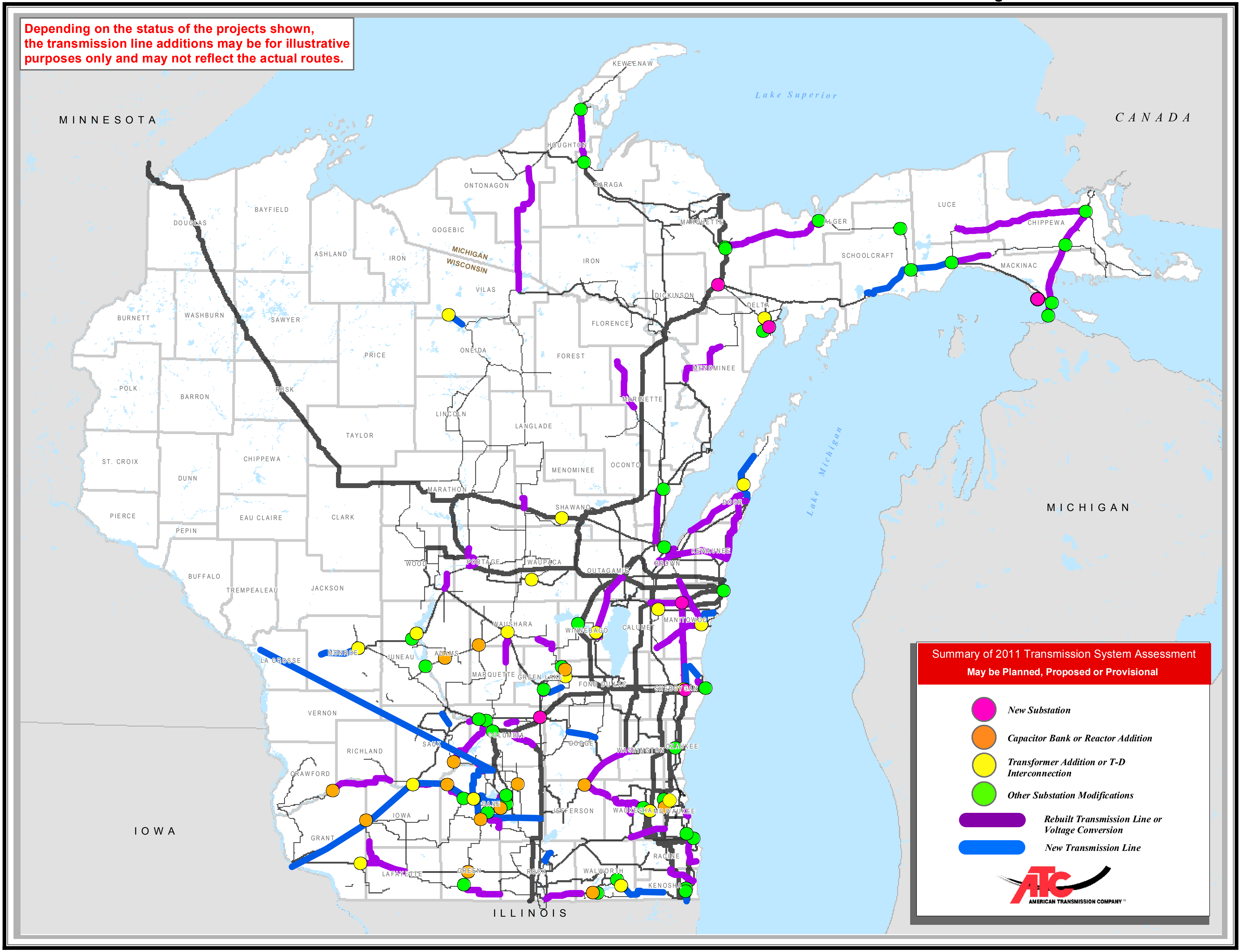
- ***Eastern Interconnection Planning Collaborative (EIPC)***
  We are among the NERC-registered Planning Authorities in the Eastern Interconnection that form the Eastern Interconnection Planning Collaborative. The EIPC group consists of 26 Planning Authorities, working with the Department of Energy, formed to develop conceptual Eastern Interconnection-wide transmission plans. The DOE has granted an award for $16 million to the group to develop transmission expansion options for the Eastern Interconnection under different scenarios. A Stakeholder Steering Committee with representatives from state regulatory bodies, transmission owners, generation owners (including renewables), end users, demand-side businesses, other suppliers, transmission-dependent utilities, public power entities and non-governmental entities has been established. They have developed eight macro-economic futures. Ultimately, three scenarios will be used to develop detailed transmission expansion options. Initial modeling results for many of the futures are available at http://www.eipconline.com/Modeling_Results.html. The project is being done in two phases and will continue through 2012, when interregional transmission options will be developed and analyzed along with a final report. We are an active participant in the EIPC and are one of eight sub-awardees of the DOE funding grant.

*Table ES-1*
*Summary of American Transmission Co.'s*
**2011 Transmission System Assessment**

| | 2010 Assessment | 2011 Assessment |
|---|---|---|
| | (September 2010) | (September 2011) |
| ***New Transmission Lines Requiring New Right-of-Way*** | | |
| 345 kV | 3 lines / 230 miles* | 4 lines / 237 miles |
| 138 kV | 7 lines / 53 miles | 9 lines / 73 miles |
| 115 kV | 1 line / 7 miles | 1 line / 7 miles |
| 69 kV | 4 lines / 24 miles | 2 lines / 17 miles |
| | | |
| ***Transmission Lines to be Constructed, Rebuilt, Reconductored or Uprated on Existing Right-of-Way*** | | |
| 345 kV | 0 lines / 0 miles | 1 lines / 51 miles |
| 161 kV | 1 line / 18 miles | 1 line / 18 miles |
| 138 kV | 8 lines / 135 miles | 10 lines / 117 miles |
| 69 kV | 12 lines / 157 miles | 10 lines / 107 miles |
| | | |
| ***New Transformers to be Installed*** | | |
| ***(# of transformers / total increase in capacity)*** | 24 transformers / 3,528 MVA | 21 transformers / 2,921 MVA |
| | | |
| ***New Capacitor Banks to be Installed*** | | |
| ***(# of installations / capacity)*** | 21 installations / 956 MVAR | 14 installations / 753 MVAR |

**includes regional multi-benefits project mileages; note in 2010 we only listed the two multi-benefits project mileages and not Bain-Zion EC (now Pleasant Prairie-Zion EC)*

Figure ES-1




*Updated July 29, 2011*

Table PR-23
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects

| Projects Canceled | Former In-Service Date | Planning Zone | Reason for Removal |
|---|---|---|---|
| Install 2-32 Mvar capacitor banks at Mukwonago 138-kV Substation | 2020 | 5 | updated load/model information |
| Construct Gwinn-Forsyth second 69-kV line | N/A | 2 | updated load/model information |
| Construct a 69-kV line from SW Ripon to the Ripon-Metomen 69-kV line | 2015 | 1 | customer postponed |
| **Projects Deferred** | **New In-Service Date** | **Planning Zone** | **Reason for Deferral** |
| Rebuild 2.37 miles of 69 kV from Sunset Point to Pearl Ave with 477 ACSR | 2012 | 4 | was 2011, easement issues |
| Rebuild M38-Atlantic 69-kV line | 2013 | 2 | New project scope, schedule and ISD now identified |
| Construct Monroe County-Council Creek 161-kV line and Timberwolf 69-kV switching station | 2014 | 1 | was 2013, regulatory issues |
| Install a 161/138-kV transformer at Council Creek Substation | 2014 | 1 | was 2013, regulatory issues |
| Uprate Council Creek-Petenwell 138-kV line | 2014 | 1 | was 2013, regulatory issues |
| Reconfigure Petenwell 138-kV bus | 2015 | 1 | was 2013, bus reconfiguration will be performed with the transformer replacement for project management efficiencies. |
| Install 3-75 MVAR capacitor banks at Bluemound Substation | 2015 | 5 | Updated load/model information |
| Rebuild Arcadian-Waukesha 138-kV lines KK9942/KK9962 | 2016 | 5 | was 2015, was uprate and provisional status (now proposed); updated study results |
| Construct new 138-kV bus and install a 138/69-kV 100 MVA transformer at South Lake Geneva Substation | 2018 | 3 | was 2016 and proposed status (now provisional); updated load/model information |
| Construct new 138-kV line from North Lake Geneva to South Lake Geneva Substation | 2018 | 3 | was 2016 and proposed status (now provisional); updated load/model information |
| Construct 69-kV double-circuit line between McCue and Lamar substations | 2019 | 3 | was 2017, updated load/model information |

Table PR-23

Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects (continued)

| Projects Deferred | New In-Service Date | Planning Zone | Reason for Deferral |
|---|---|---|---|
| Construct Spring Valley-Twin Lakes-South Lake Geneva 138-kV line | 2019 | 3 & 5 | was 2018; updated load/model information |
| Rebuild the Y-119 Sun Valley Tap to Oregon 69-kV line | 2020 | 3 | was proposed in 2014 and formerly named Verona to Oregon, increased line ratings |
| Replace two existing 345/138-kV transformers at Arcadian Substation with 1-500 MVA transformer | 2020 | 5 | was 2015; updated study results |
| Install 4-49 MVAR 138-kV capacitor banks at Concord Substation | 2020 | 3 | was 2019, updated load/model information |
| Install 2-16.33 Mvar 69-kV capacitor banks at North Monroe | 2021 | 3 | was 2018, updated load/model information |
| Install 1-16.33 MVAR 69-kV capacitor bank at Verona Substation | 2021 | 3 | was 2018, updated load/model information |
| Construct second Dunn Road-Egg Harbor 69-kV line | 2021 | 4 | was 2018, updated load/model information |
| Install 2-16.33 Mvar 69-kV capacitor banks at Sun Prairie | 2022 | 3 | was 2020, updated load/model information |
| Install 2-12.25 MVAR 69-kV capacitor banks at Mazomanie Substation | 2023 | 3 | was 2020, updated load/model information |
| Replace two existing 138/69-kV transformers at Glenview Substation with 100 MVA transformers | 2025 | 4 | was 2020, updated load/model information |
| **Other Project Changes and Possible Changes** | **In-Service Date** | **Planning Zone** | **Nature of Change or Update** |
| Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 230 F degree summer emergency ratings | 2012 | 2 | Project completed ahead of schedule due to availability of construction resources and required outages |
| Install 1-8.16 MVAR capacitor bank at Boscobel 69-kV Substation and upgrade existing 5.4 MVAR bank with an 8.16 MVAR bank | 2015 | 3 | was 2019, Gran Grae 161/69-kV transformer prior outage issues |

Table PR-23
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects (continued)

| Other Project Changes and Possible Changes | In-Service Date | Planning Zone | Nature of Change or Update |
|---|---|---|---|
| Construct Fairwater-Mackford Prairie 69-kV line | 2017 | 1 | ISD may be bought forward if project shows economic benefit. |
| Reconfigure the North Randolph-Ripon 69-kV line to form a second Ripon-Metomen 69-kV line and retire the circuit between Metomen and the Mackford Prairie tap | 2017 | 1 | ISD may be bought forward if project shows economic benefit. |
| Uprate the 6986 Royster to Sycamore 69-kV line to 115 MVA | 2018 | 3 | was 2019, updated load/model information |
| **New Projects** | **In-Service Date** | **Planning Zone** | **Reason for Project** |
| Rebuild Pleasant Prairie 345-kV bus | 2013 | 5 | operating flexibility |
| Construct Pleasant Prairie-Zion Energy Center 345-kV line | 2014 | 5 | economics |
| Construct 138-kV lines to serve Milwaukee County T-D interconnection | 2015 | 5 | T-D interconnection |
| Construct Badger Coulee 345-kV line | 2018 | 3 | policy benefits |
| Convert Forest Junction - Howards Grove and a portion of the Howards Grove - Holland 138-kV circuits to 345-kV | 2018 | 4 | new generation |
| Barnhart Substation: Construct new 345/138-kV substation with new 500 MVA 345/138-kV transformer | 2018 | 4 | new generation |
| Branch River Substation:  Construct new 345-kV switching station | 2018 | 4 | new generation |
| Uprate the Edgewater-Cedarsauk 345-kV circuit | 2018 | 4 | new generation |
| Construct a new Barnhart - Plymouth - Howards Grove - Erdman 138-kV circuit | 2018 | 4 | new generation |
| Point Beach Substation: Install new series 345-kV breaker for circuit Q-303 | 2018 | 4 | new generation |

Table PR-23
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects (continued)

| New Projects | In-Service Date | Planning Zone | Reason for Project |
|---|---|---|---|
| Construct Dubuque-Spring Green-Cardinal 345-kV line | 2020 | 3 | policy benefits |
| Uprate Oak Creek-Bluemound 230-kV line | 2021 | 5 | operating flexibility |
| Rebuild West Middleton-Pheasant Branch 69-kV line with double circuits to achieve a 240 MVA SE on each circuit | 2022 | 3 | updated load/model information |