October 2009 10-Year Assessment
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Regional planning and participation: Putting customers' needs first
Providing a reliable, cost-effective transmission system for our customers remains our number one goal. At the same time, the emphasis on global climate change and increased reliance on renewable fuels is changing the landscape. Wind is the leading renewable "fuel," and with an increased emphasis on state-mandated portfolio standards, more transmission infrastructure is needed to move the energy from the wind-rich areas west of us to where it can be used. While we have successfully put the power of more than 400 megawatts of wind on the wires within our footprint, there are many policy decisions that will affect how much wind generation will be built, where it will be located and how it will be integrated with the existing system to maintain reliability.

At American Transmission Co., we believe the best plans are developed through an open, participative process that puts customers' needs first. Through our participation in a number of regional and inter-regional initiatives, we are working to identify projects that meet not only reliability needs, but support policy initiatives related to climate change and other issues, along with improved access to the regional market. Our approach is based on two critical foundations – comprehensive analysis and collaboration.

In this year's 10-Year Assessment, we continue our process of assessing and reassessing the needs of existing and anticipated system users, individually and collectively, according to accepted industry criteria and practices. Our goal is to initially determine, and then evolve over time, the best set of transmission projects that meet those needs. "Best" means striking the right balance among reliability, risk, cost and societal impact so that the resulting plan is publicly acceptable and constructible.

While our reliability performance data indicates that our system is performing well, we continue to emphasize managing the risk of aging infrastructure, ensuring reliable performance and safety into the future. Where previous assessments have discussed near-term asset renewal efforts, this year we have extended the detail of our potential asset renewal projects through the full 10-year horizon.

The 2009 Assessment identifies $2.5 billion in necessary transmission system improvements. The total includes $1 billion for transmission network upgrades specifically described in this report, along with $1.5 billion in interconnection and asset renewal projects, infrastructure replacements and relocations, and other smaller network reliability improvements.

While the cost estimate in our 2009 Assessment is slightly less than the $2.7 billion identified in last year's report, our 10-year capital spending may need to be increased because of increased focus on regional transmission support to move renewable generation to areas where the power is needed. With more than $2.1 billion invested in the system since 2001, we have become a recognized, national leader in planning, permitting and building electric transmission infrastructure. Please refer to the Projects section for a list of specific projects in each zone identified to improve reliability.

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Capital cost

Based on this 2009 Assessment, the total cost estimate for needed transmission system improvements is about $2.5 billion over the next 10 years (through 2018). The total $2.5 billion in projects, expressed in constant (inflation adjusted) year dollars, can be broken down into the following categories.

Category	*2008 10-year capital estimate in billions*	*2009 10-year capital estimate in billions*
10-Year Assessment projects	$1.30	$0.97
Asset Renewal	$0.46	$0.70
Generator interconnections	$0.29	$0.17
Distribution interconnections	$0.16	$0.17
Protection & control	$0.08	$0.07
Network	$0.10	$0.09
Unspecified network projects	$0.23	$0.26
Other *	$0.09	$0.11
Total expenditures	$2.71	$2.54

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

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

	March 2006	Nov 2006	Nov 2007	Oct 2008	Oct 2009
Specified 10-Year Assessment Projects	$2.1B	$1.7B	$1.4B	$1.3B	$1.0B
Other Capital Expenditures	$1.3B	$1.4B	$1.4B	$1.4B	$1.5B
Total 10-Year Capital Cost	$3.4B	$3.1B	$2.8B	$2.7B	$2.5B

In the 2009 Assessment, we project a reduced total cost estimate for all needed transmission system improvements over a rolling 10-year period. Although the proportionate share of cost of projects specifically detailed in the assessments continues to decrease, the overall total is relatively static as a result of an increase in Asset Renewal expenditures. In addition, we are evaluating several higher-voltage transmission projects to support the need for regional renewables. If these scenarios emerge, we project that there will be additional capital expenditures in the 10-year planning period.

Other issues that can influence the total 10-year cost up or down as each future assessment is completed includes the following factors:

- Completion of prior projects that improve reliability and renew assets,
- Changing load forecast,
- Changes in generation and distribution interconnection projects,
- Improved resource planning to manage construction projects
- Changes in mandatory reliability standards,
- Additional projects that are driven by economic benefits and
- Changing equipment and labor costs.

Referring to the breakdown of the 2009 total cost, unspecified network projects are defined as those projects that may shift into the 10-year timeframe because of factors listed earlier. This $258 million represents anticipated costs from projects not defined in the assessment, but potentially driven by some combination of the following issues that we continue to analyze:

- Reliability impacts to our customers, both short- and long-term
- Regional impacts to our customers,
- Economic impacts to our customers, and
- Multiple outage impact solutions.

Future assessments will continue to define these unspecified costs as issues are further defined in the continuing planning process.

Table 2009_Financial outlines the costs of network and economic assessment projects and ATC construction projects overall.

Reliability for renewable energy: helping states meet their renewable goals
In addition to providing updated need and project information, the 2009 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, exploratory transmission initiatives being investigated by the Midwest ISO, and wind generation developments. The latest developments are summarized below.

- *The Joint Coordinated System Plan Study*
  This joint effort among several regional transmission organizations (RTOs) issued its final report earlier this year. The study was performed in coordination with a Department of Energy study of wind integration in the Eastern Interconnection. Conceptual transmission overlays were identified for two future generation development scenarios – a reference scenario and a 20-percent wind scenario for the U.S. footprint in the Eastern Interconnection excluding Florida.

  It is currently unclear whether RTO's will continue participating in the study effort or when the next study cycle will begin. Refer to the study website, http://www.jscpstudy.org, for more details.

- *Midwest ISO Regional Generation Outlet Study I and II (RGOS)*
  The Midwest ISO initiated RGOS -- Phase I as a targeted study as part of a larger process. The objective is to identify a set of regionally coordinated transmission projects that interconnect and deliver new wind generation based on renewable portfolio standards in Illinois, Iowa, Minnesota and Wisconsin. This effort also collaborates with the Upper Midwest Transmission Development Initiative (UMTDI) effort, as the initiative requested this study to support its transmission development effort.

  In March 2009, the UMTDI executive committee directed the Midwest ISO to conduct detailed analyses of the indicative transmission plans for two wind zone scenarios developed in RGOS and modified by UMTDI. The results are scheduled to be available by the end of October 2009. The Midwest ISO kicked-off RGOS--Phase II in May 2009, which will identify the transmission alternatives needed to implement new or expanded renewable portfolio standards and other renewable goals not necessarily addressed in the RGOS Phase I study. Please refer to the Regional Planning section for more information.

- *Michigan Wind Energy Resource Zone Board*
  This is a special council created by Michigan legislation that will identify one or more areas that could become prime wind energy production zones. Currently, the board has listed four zones for further study, all in the Lower Peninsula of Michigan. A secondary list of sites that did not meet prime siting or high-production criteria included one Upper Peninsula zone in the Keewenaw Peninsula. Preliminary studies by the board and a Michigan university had pointed to a few additional potential wind production areas in the U.P. where generation development could occur in the future. We are following the developments of this special council.

- *Minnesota Renewable Energy Standard Studies*
  Minnesota transmission-owning utilities conducted three studies to identify the next round of transmission upgrades that will help meet the stat's renewable energy standard milestone in 2016. Reports can be found on the Minnesota Electric Transmission Planning website at www.minnelectrans.com. We pay close attention to these study efforts to determine what impact the identified plans would have on transmission development in and around Wisconsin and communicate with the Minnesota utilities regarding study details so as to participate in ongoing and future joint studies.

- *SMARTransmission Study*
  The currently underway Strategic Midwest Area Renewable Transmission (SMAR*Transmission)* Study is a collaborative effort among ATC, American Electric Power, MidAmerican Energy Co., Exelon, Xcel Energy and NorthWestern Energy Corp. to identify potential extra-high voltage (345-, 500- and 765-kilovolt) projects that could be needed to move wind power within a nine-state region from the Dakotas to Ohio, including the areas covered by the RTOs of SPP, MISO and PJM.

  As part of this study, transmission alternatives will be analyzed for impact, and economic benefits of several options will be quantified. The outcome of the SMAR*Transmission* Study in combination with other studies currently being performed by the Midwest ISO will be used as input to the regional transmission planning processes and result in transmission projects being identified. This study is scheduled for completion in January 2010.

- *Upper Midwest Transmission Development Initiative (UMTDI)*
  The governors of five states (North Dakota, South Dakota, Minnesota, Iowa and Wisconsin) launched this initiative in September 2008. The goal is to promote regional electric transmission investment and cost sharing that supports these states' commitment to cost-effective renewable generation while maintaining reliability. This initiative includes two charges – development of a transmission plan and a cost sharing methodology. A major input that supports this effort is RGOS Phase I, organized by the Midwest ISO. We, along with other transmission owners and stakeholders in these five states have been participating in and providing input to both the UMTDI and Midwest ISO efforts. It is possible that UMTDI will recommend a transmission plan and a cost-allocation approach by the end of 2009.

Planning for a reliable future
Since publishing last year's assessment, we've energized a number of components that provide reliability benefits to our customers.

- Gardner Park-Central Wisconsin – Construction was completed on a new 50-mile 345-kilovolt line between the Gardner Park Substation near the Weston Power Plant and the new Highway 22 Substation in central Shawano County. The 345-kilovolt line supports output of the Weston Power Plant and strengthens reliability.
- Morgan-Werner West 345-kilovolt and Werner West-Clintonville 138-kilovolt lines –This project relieves electric system congestion in and around Green Bay, provides additional transfer capability and improves electric system reliability.
- North Madison-Huiskamp – This new, five-mile, 138-kilovolt transmission line in Dane County resolves thermal overloads in the area.
- Cranberry-Conover-Plains –The Cranberry-Conover 115-kilovolt transmission line was completed in 2008. The overall reinforcement project also includes the rebuild and conversion of the Conover-Iron River-Plains 69-kilovolt line to 138-kilovolt operation by 2010. This alternative addresses the long-term reliability issues of the Rhinelander Loop, provides substantial voltage support to the 69-kilovolt system in the western portion of the Upper Peninsula and addresses potential long-term condition issues due to the age of the existing 69-kilovolt system.

Another aspect of reliability involves customers' distribution and/or generator interconnections. Several unanticipated large-customer interconnections have recently developed in our service territory. Ethanol plants have been interconnected within the last two years. A large gas distributor is installing a pumping station for a pipeline extension to northeast Wisconsin. Several economic development opportunities in Michigan's Upper Peninsula may also require new distribution interconnection facilities. Additional interconnections are also being developed to support pollution control equipment that is being added at two coal fired power plants. For more information, see T-D Interconnections.

While natural gas generation dominated new energy proposals in recent years, new proposals now focus on wind generation. Currently, more than 16 proposals to install more than 1,371 megawatts of wind turbines in Wisconsin are in the Midwest ISO generation queue. For more on generation developments in Wisconsin and Michigan's Upper Peninsula, see Generation Interconnections.

Engaging the public in our plans

Our approach to transmission planning is built upon two critical foundations – comprehensive engineering analyses and collaborative communications.

We are continually assessing and reassigning the needs of existing and anticipated system users, individually and collectively, according to accepted industry system performance criteria and practices. Our goal is to initially determine, and then evolve over time, the best set of transmission projects to address those needs.

In addition to identifying reliability-based projects to address system needs, we are engaging stakeholders to identify the most important economic benefit projects. Through collaboration with stakeholders, projects to connect our system to renewable energy from the west and to relieve congestion around southern Lake Michigan have been identified for economic analysis in 2009. Six alternatives have been identified to connect our system to renewable resources in the west, including multiple variations of a La Crosse – Madison area 345-kilovolt circuit, a low-voltage alternative to this path, a 765-kilovolt by-pass of this path, and a Dubuque, Iowa to Madison area 345-kilovolt alternative. In order to relieve congestionaround southern Lake Michigan, a 345-kilovolt circuit connecting southeast Wisconsin to northeast Illinois will be studied as well.

The economic analysis studies of these seven project alternatives will determine the economic benefits that each alternative may provide to the ATC footprint. This information can be combined with the results of other studies to determine which project alternatives merit further investigation.

Since economic analyses may be used in the prioritization and staging of projects, an attempt is made to capture all relevant factors in determining the economic benefits of a project. We test such projects against multiple plausible futures for Wisconsin's electric industry, such as robust or slow economic growth, regulatory changes, and fuel supply volatility. The futures are based upon key drivers such as load growth, generation retirement and expansion, fossil-fuel costs, use of renewable energy, and increased environmental regulation. The specific futures analyzed in the 2009 assessment include slow economic growth and 20 percent energy from wind. This process also uses pre-analysis stakeholder input and is described more thoroughly in the Economic Analysis section.

Besides those described in the Reliability for renewable energy section described above, several collaborative efforts are underway and are described below:

- *ATC Energy Collaborative-Michigan*
  Even with significant upgrades to transmission infrastructure in the Upper Peninsula in recent years, operational challenges remain due to the delicate balance among generation, load, market flows and transmission that currently exists.
  To verify our planning assumptions for the intermediate (three- to five-year) and long term (10-15 year) periods before future projects are proposed, we engaged stakeholders during

2008 in a collaborative process across the U.P. to examine the bounds of several plausible futures. We developed a set of core transmission system needs across the Upper Peninsula, and we are continuing to work with stakeholders on a plan that will provide continued reliability and more operational flexibility. This plan may impact the Lower Peninsula of Michigan and Canada, as well as the U.P. and northern Wisconsin. Please refer to our U.P. Collaborative section for more details.

- *Eastern Interconnection Planning Collaborative (EIPC)*
  The EIPC consists of a group of 23 Planning Authorities, working with the Department of Energy, formed to develop conceptual Eastern Interconnection-wide transmission plans. ATC is an active participant in EIPC, which has submitted a bid to perform Eastern Interconnection-wide planning in response to a DOE funding opportunity. The DOE's proposal selection is expected by early November, 2009 and a final contract is expected by the end of this year.

- *Western Wisconsin Reliability Study*
  This study is currently underway and is being led by ATC with participation by Xcel Energy; Dairyland Power Cooperative; Great River Energy; International Transmission Co., Midwest; Southern Minnesota Municipal Power Agency; and coordination with the Midwest ISO. The purpose of this study is to investigate reliability needs in western Wisconsin, and to identify projects that could address the identified needs. This study is expected to be complete in the second quarter of 2010.

- *La Crosse-Madison 345-kilovolt line*
  We continue with efforts begun in 2008 to work with stakeholders in identifying projects that provide economic benefits and upgrades that could improve access to lower-cost sources of power inside and outside our service territory. Stakeholders continue to express significant interest in a high-voltage line between La Crosse and Madison; it also is believed that the line would support the Upper Midwest Transmission Development Initiative to meet renewable portfolio standards in the region.

- *Organization of MISO States Cost Allocation and Regional Planning*
  The Organization of MISO States (OMS) launched its cost allocation and regional planning (CARP) effort in January 2009 to address the issue of cost allocation for transmission in the Midwest ISO, including developing indicative transmission plans to illustrate the amount of transmission that might be needed in various scenarios and the associated costs.

  During the first half of 2009, the group – which includes representatives from each of the 13 state regulatory commissions in the Midwest ISO – has identified assumptions and scenarios that will be used in developing transmission plans. In June of 2009, this group also began its investigation of alternatives to the current Midwest ISO cost-allocation methods for transmission. After reviewing various alternatives, the group will determine whether to further pursue the adoption of one of those alternative methods or to revise the current methods.

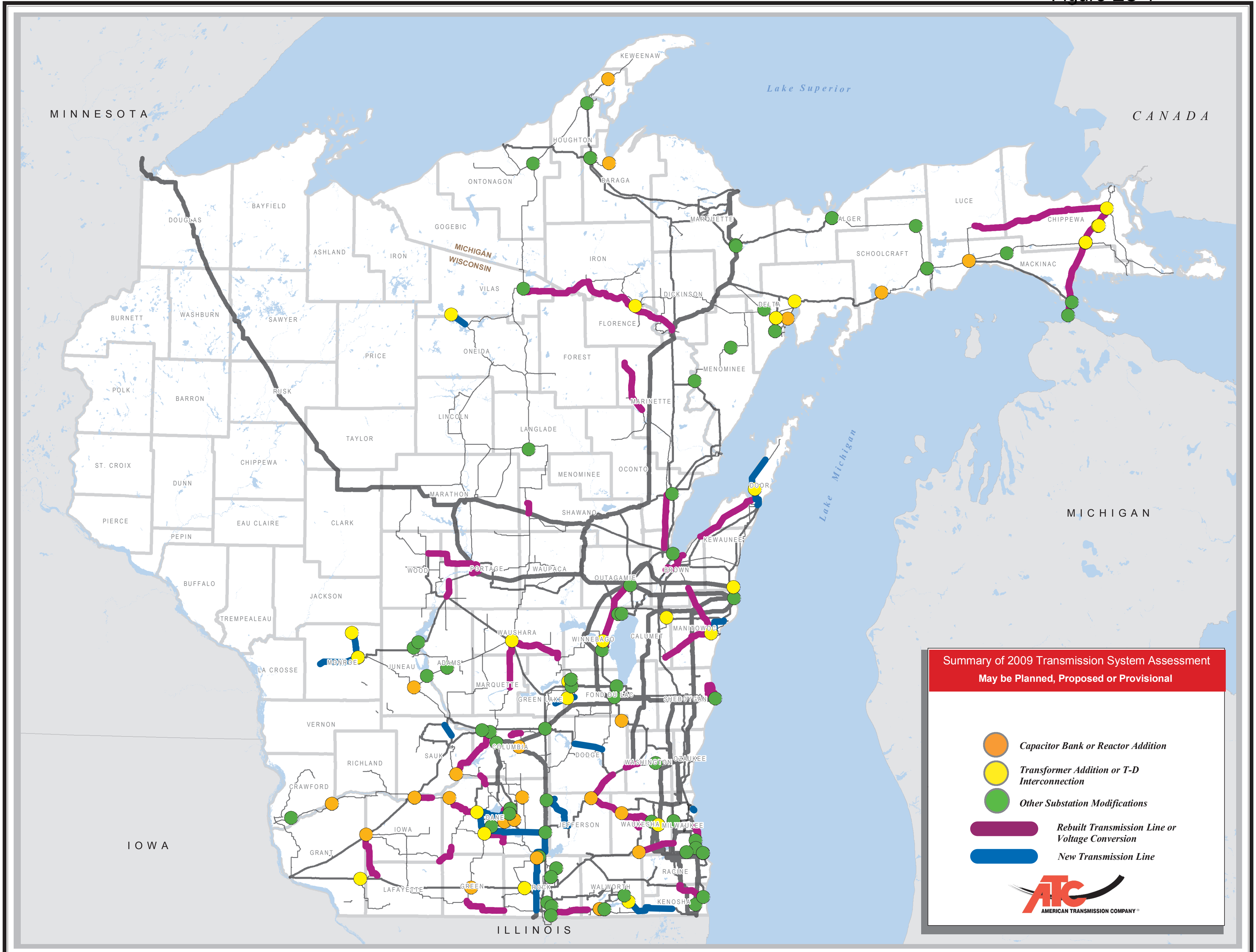
Asset renewal
Our Planning and Asset Management departments work closely together to maintain and improve system reliability. System reliability is improved by focusing upon the life-cycle management of our transmission assets. The coordination of design, commissioning, operation, maintenance and replacement strategy are necessary to achieve this objective. Asset renewal is the "replacement strategy" piece of the asset life cycle. Asset renewal is driven by public and worker safety, regulatory compliance, reliability performance as defined by criticality, and environmental stewardship. For details about this program, please refer to the Asset Renewal section.

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 help us identify the best-possible system improvements that serve multiple purposes and reduce overall cost. This year's assessment includes $750 million in asset renewal work, which includes maintenance and protection projects. Please refer to the 2009 Asset Renewal Financial Table for details.

Ever mindful of the environment
With a construction program of nearly $250 million each year, we recognize that our work has an impact on the environment. We take our commitment to environmental protection and stewardship seriously – our goal is to avoid making impacts where we can, minimize those that can't be avoided and restore the environment. In some instances, we can improve conditions when our work is finished. Please refer to Routing & Siting for details regarding our environmental efforts.

Table ES-1 Summary of American Transmission Co.'s **2009 Transmission System Assessment**		
	2008 Assessment	**2009 Assessment**
	(October 2008)	(October 2009)
New Transmission Lines Requiring New Right-of-Way		
345 kV	2 lines / 82 miles	1 lines / 32 miles
138 kV	10 lines / 84 miles	7 lines / 62 miles
115 kV	1 line / 7 miles	1 line / 7 miles
69 kV	6 lines / 36 miles	6 lines / 30 miles
Transmission Lines to be Constructed, Rebuilt, Reconductored or Uprated on Existing Right-of-Way		
345 kV	3 lines / 102 miles	2 lines / 50 miles
161 kV	1 line / 20 miles	1 line / 18 miles
138 kV	17 lines / 320 miles	10 lines / 243 miles
69 kV	11 lines / 107 miles	11 lines / 88 miles
New Transformers to be Installed		
(# of transformers / total increase in capacity)	23 transformers / 3,373 MVA	21 transformers / 2,827 MVA
New Capacitor Banks to be Installed		
(# of installations / capacity)	39 installations / 1,412 MVAR	29 installations / 1,100 MVAR

Figure ES-1



Modified: September 28, 2009

FP	*10-Year Assessment Network Project Description*	*Sum of Previous Expenditures as of 12/31/2008*	*Sum of Future Expenditures 2009-2018*	*Total Capital Expenditures 2001-2018*
F1435	Construct 345-kV line from Rockdale to West Middleton	$0	$206,059,928	$206,059,928
F0823	Construct Morgan-Werner West 345-kV line	$100,772,701	$47,231,596	$148,004,297
F1981	Paddock-Rockdale 345-kV line	$35,072,011	$82,484,322	$117,556,333
F1363	Cranberry-Conover-Iron River-Plains project	$62,863,422	$45,630,527	$108,493,949
F2570	Spring Valley-Twin Lakes-South Lake Geneva 138-kV line	$0	$78,923,833	$78,923,833
F2466	West Middleton-Blount 138-kV line	$0	$60,810,250	$60,810,250
F2833	Rebuild/convert Straits-Pine River 138-kV lines 6904/5	$0	$37,316,887	$37,316,887
F2454	Construct Monroe County-Council Creek 161-kV line	$17,174	$31,158,476	$31,175,650
F0924	Construct a Jefferson-Stony Brook 138-kV line	$12,728,966	$16,882,800	$29,611,766
F2836	Construct tap from Kinross load to Pine River/Nine Mile 69-kV line	$0	$23,099,097	$23,099,097
F2252	Rebuild Arpin-Rocky Run 345-kV line	$872,052	$21,881,891	$22,753,942
F1407	Oak Ridge-Verona 138-kV line	$5,614,799	$11,247,007	$16,861,805
F1358	Construct 138-kV line from Canal to Dunn Road	$25,423	$15,755,915	$15,781,338
F2587	Construct new 138-kV line from North Lake Geneva to South Lake Geneva Substation	$0	$14,717,000	$14,717,000
F1640	Construct a Horicon-East Beaver Dam 138-kV line	$0	$13,390,698	$13,390,698
F2495	Construct 115-kV line from new Woodmin Substation to the Clear Lake Substation	$0	$12,200,000	$12,200,000
F2437	Kewaunee SS-Bus Reconfiguration	$0	$11,923,864	$11,923,864
F2526	Y33 Brodhead-South Monroe rebuild	$0	$11,832,423	$11,832,423
F1670	Y32 Colley Road-Brick Church uprate	$0	$11,225,500	$11,225,500
F1638	Construct a Lake Delton-Birchwood 138-kV line	$0	$9,489,119	$9,489,119
F1282	Construct ring bus at the Pine River 69-kV Substation and replace 1-5.4 MVAR capacitor bank with 2-4.08 MVAR banks	$1,140,014	$7,900,386	$9,040,400
F2834	Install 138/69-kV 150 MVA transformers at Pine River and Nine Mile	$0	$8,620,963	$8,620,963
F2558	Construct 69-kV double-circuit line between McCue and Lamar substations	$0	$8,522,646	$8,522,646
F2539	Arcadian transformer replacements	$0	$7,276,385	$7,276,385
F2140	Elm Road Phase II Upgrades	$6,831,910	$8,364	$6,840,273
F2173	Warrens DIC	$456,953	$6,274,180	$6,731,133
F2081	Shoto-Custer 138-kV line	$0	$6,443,929	$6,443,929
F0181	Construct a second Dunn Road-Egg Harbor 69-kV line	$0	$6,097,939	$6,097,939
F2628	Replace two overhead Blount-Ruskin 69-kV lines with one underground 69-kV line	$2,092	$6,089,799	$6,091,892
F2487	Shorewood-Cornell underground 138-kV Line	$57,811	$5,939,382	$5,997,193
F1602	line	$173,952	$5,818,223	$5,992,176
F2079	Replace Glenview transformer	$0	$5,869,778	$5,869,778
F2105	Construct Fairwater-Mackford Prairie 69-kV line	$0	$5,685,596	$5,685,596
F1869	Install transformer and bus at Bass Creek	$159,651	$5,381,591	$5,541,242
F2327	Spring Green capacitor banks	$222,055	$5,263,409	$5,485,464
F2080	Sunset Point transformer replacements	$0	$5,371,145	$5,371,145
F2404	Brick Church capacitor banks	$13,870	$5,158,376	$5,172,246
F2469	Rebuild the Verona to Oregon 69-kV line Y119	$0	$5,086,042	$5,086,042
F1444	Uprate Y-40 Gran Grae-Boscobel 69-kV line to achieve a 99 MVA summer emergency rating	$199,728	$4,427,807	$4,627,535

FP	*10-Year Assessment Network Project Description*	*Sum of Previous Expenditures as of 12/31/2008*	*Sum of Future Expenditures 2009-2018*	*Total Capital Expenditures 2001-2018*
F2445	Install a second 138/69-kV transformer at Spring Green with a 100 MVA summer normal rating	$0	$4,436,285	$4,436,285
F2088	Fitchburg-Nine Springs Uprate	$34,037	$4,390,576	$4,424,613
F1867	Replace 138/69-kV transformer at Metomen	$0	$4,385,418	$4,385,418
F2480	Wautoma Substation second transformer	$0	$4,029,502	$4,029,502
F2112	GIC 012 Elm Road Unit 1 Phase II	$3,652,075	$41,421	$3,693,496
F1619	Bayport-Pioneer Phase I	$0	$3,624,449	$3,624,449
F2650	Install 3-75 MVAR capacitor banks at Bluemound Substation	$0	$3,466,950	$3,466,950
F2093	North Randolph 500 MVA transformer	$0	$3,407,728	$3,407,728
F2489	Concord capacitor bank installation	$0	$3,358,282	$3,358,282
F2485	M38 Substation-capacitor bank-Bus Expansion	$144,983	$2,902,236	$3,047,219
F2475	Sun Prairie 69-kV capacitor banks.	$0	$2,566,334	$2,566,334
F0339	Install a second 138/69-kV transformer at Hillman	$0	$2,531,712	$2,531,712
F2371	Kewaunee Substation-Repl OCB-TAT	$155,625	$2,366,105	$2,521,730
F1361	Rebuild 2.37 miles of 69 kV from Sunset Point to Pearl Ave with 477 ACSR	$604,547	$1,916,802	$2,521,349
F2086	Pleasant Valley T-D (second transformer)	$7,069	$2,409,950	$2,417,019
F2516	Femrite capacitor banks	$0	$2,404,642	$2,404,642
F2472	North Monroe 69-kV capacitor banks	$0	$2,336,040	$2,336,040
F1844	Construct Brandon-Fairwater 69-kV line	$258,223	$2,012,520	$2,270,743
F2222	Install 1-16.33 MVAR capacitor bank at Hiawatha 138-kV Substation	$99,560	$2,146,978	$2,246,538
F2248	Sheepskin Substation Relay Upgrades	$655,921	$1,570,610	$2,226,531
F2473	Oak Creek-Pennsylvania 138-kV Line KK837 Upgrade	$0	$2,224,208	$2,224,208
F2474	Dam Heights 69-kV capacitor banks	$0	$2,150,064	$2,150,064
F2092	Uprate Portage-Trienda 138-kV line	$0	$2,026,175	$2,026,175
F2256	Summit capacitor banks	$32,511	$1,765,726	$1,798,236
F2324	Lamar DIC	$139,389	$1,579,974	$1,719,363
F2517	Mazomanie 69-kV capacitor banks	$0	$1,681,113	$1,681,113
F2520	Verona capacitor bank	$0	$1,572,509	$1,572,509
F2515	Eden 69-kV capacitor banks	$0	$1,568,118	$1,568,118
F2490	North Bluff SS-Install capacitor bank	$0	$1,447,034	$1,447,034
F2154	Uprate Walworth- North Lake Geneva 69-kV to 69 MVA	$235,466	$1,132,210	$1,367,676
F2518	Boscobel SS 69-kV capacitor banks	$0	$1,335,173	$1,335,173
F2468	Osceola Substation-install capacitor bank	$77,015	$1,053,019	$1,130,034
F1729	Elm Road TSR Phase II circuit breakers	$757,568	$338,165	$1,095,733
F2491	Uprate Castle Rock-Mckenna 69-kV line	$0	$1,093,828	$1,093,828
F2153	Uprate Brick Church-Walworth 69-kV line to 115 MVA	$0	$960,370	$960,370
F1819	Install 1-5.4 MVAR capacitor bank at L'Anse 69 kV	$59,368	$848,959	$908,326
F2405	Uprate Y-79 McCue-Milton Lawns 69-kV line	$88,592	$801,715	$890,306
F2477	Ripon Substation capacitor banks	$0	$801,448	$801,448
F2471	6986 Royster-Sycamore uprate	$0	$790,584	$790,584
F2560	Convert Necedah distribution substation from 69 kV to 138 kV	$0	$761,500	$761,500
F2317	Royster Substation breaker replacement	$140,015	$553,825	$693,840
F2016	Uprate Chandler-Cornell 69-kV line clearance from 120 to 167 deg F	$222,213	$427,283	$649,496

ATC 2009 10-Year Assessment
Summary of Network Capital Expenditures (2009-2018)
10-Year Assessment Project Detail

FP	*10-Year Assessment Network Project Description*	*Sum of Previous Expenditures as of 12/31/2008*	*Sum of Future Expenditures 2009-2018*	*Total Capital Expenditures 2001-2018*
F2223	Install 1-16.33 MVAR capacitor bank at Indian Lake 138-kV Substation	$0	$642,044	$642,044
F2532	Lakehead 69-kV line uprate	$34	$601,487	$601,520
F1403	kV	$0	$596,084	$596,084
F2493	Mukwonago Capacitor bank	$0	$517,960	$517,960
F1988	Point Beach SS Line 111 Upgrades	$145,262	$335,017	$480,280
F2398	Replace Metomen 69-kV breaker	$17,984	$400,272	$418,256
F2519	McKenna 69-kV capacitor bank	$0	$326,860	$326,860
F2142	Uprate Arcadian-Waukesha 138-kV lines KK9942/KK9962	$79,441	$242,639	$322,080
F2461	Upgrade Bain-Albers 138-kV Line	$5,249	$298,325	$303,574
F2434	Tayco - Melissa OPGW Line 138124	$49,954	$172,173	$222,127
F2534	Delta 1 69-kV line uprate	$0	$145,304	$145,304
F2135	Uprate Columbia 345/138-kV transformer T-22 to 527 MVA	$0	$108,590	$108,590
F2849	Uprate Council Creek-Petenwell 138-kV line	$0	$67,057	$67,057
F2535	Delta 2 69-kV line uprate	$0	$38,439	$38,439
F1868	Uprate Y-61 Sheepskin-Dana 69-kV line to 95 MVA	$34,249	$0	$34,249
F2053	Construct a 69-kV line from SW Ripon to the Ripon-Metomen 69-kV line	$0	$0	$0
F2476	Install a 12.2 MVAR capacitor bank at Hilltop 69-kV Substation	$0	$0	$0
F2557	Rio capacitor banks	$0	$0	$0
2009 TYA Totals Reported		**$238M**	**$962M**	**$1,207M**
Plus projects completed prior to 1/1/2009		**$1.891**		
Plus non-network projects in TYA			**$1.578B**	
Total ATC Capital Expenditures		**$2.129B**	**$2.54B**	

Table PR-23			
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2009 10-Year Assessment			
PROJECTS CANCELED	**Former In-Service Date**	**Planning Zone**	**Reason for Removal**
A second distribution transformer at Somers Substation requires a rebuild of the Racine-Somers-Albers 138-kV line; extend Albers 138-kV bus to permit connecting the Racine-Somers-Albers radial line to the Albers 138-kV bus	2011	5	Updated study results
Construct a 345-kV bus at Bain Substation	2008	5	Updated study results
Install a second 138/69-kV transformer at McCue Substation	2016	3	Updated study results
Upgrade Bain-Kenosha 138-kV line	2013	5	Equipment replaced during construction of another project
Install 2-16.3 MVAR capacitor bank at Mears Corners 138-kV Substation	TBD	4	Updated load/model information
Install 2-16.3 MVAR capacitor bank at Rosiere 138-kV Substation	TBD	4	Updated load/model information
Construct Evansville-Brooklyn 69-kV line	TBD	3	Updated load/model information
Construct Verona-North Monroe 138-kV line	TBD	3	Updated load/model information
Replace the 1200 A breaker at Edgewater T22 345/138-kV transformer	TBD	4	Equipment replaced during construction of another project
Uprate 138-kV line from Kewaunee to East Krok	TBD	4	Updated load/model information
Rebuild Blaney Park-Munising 69 kV to 138 kV	2014	2	Upper Peninsula Collaborative updated study results
Install 2-16.3 MVAR capacitor bank at Aviation Substation	TBD	4	Updated load/model information
PROJECTS DEFERRED	New Date	Planning Zone	Reason for Deferral
Construct a 138-kV bus at Pleasant Valley Substation to permit second distribution transformer interconnection	2010	5	Was 2009; Resource scheduling requirements
Uprate Y-61 McCue-Lamar 69-kV line to achieve 300 deg F line ratings and install 2-12.45 Mvar 69-kV capacitor banks at Lamar Substation	2010	3	Was 2009 and provisional status; now proposed; delay due to resource scheduling requirements
Rebuild 2.37 miles of 69 kV from Sunset Point to Pearl Ave with 477 ACSR	2011	4	Was 2009; Resource scheduling requirements

Table PR-23			
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2009 10-Year Assessment			
PROJECTS DEFERRED	**New date**	**Planning Zone**	**Reason for Deferral**
Install 3-75 MVAR capacitor banks at Bluemound Substation	2012	5	Was 2010; Resource scheduling requirements
Construct Monroe County-Council Creek 161-kV line and Timberwolf 69-kV switching station	2013	1	Was 2012; coordination with other entities
Install a 161/138-kV transformer at Council Creek Substation	2013	1	Was 2012; coordination with other entities
Uprate Council Creek-Petenwell 138-kV line	2013	1	Was 2012; coordination with other entities
Rebuild Y-32 Colley Road-Brick Church 69-kV line	2013	3	Was 2012; Resource scheduling requirements
Uprate X-12 Town Line Road-Bass Creek 138-kV line to 300 deg F	2013	3	Was 2012; Resource scheduling requirements
Uprate Arcadian-Waukesha 138-kV lines KK9942/KK9962	2013	5	Was 2010 proposed status, now provisional; updated study results
Replace two existing 345/138-kV transformers at Arcadian Substation with 1-500 MVA transformer	2013	5	Was 2010, Resource scheduling requirements
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 2013; updated load/model information
Upgrade Oak Creek-Pennsylvania 138-kV line	2015	5	Was 2014; updated load/model information
Install a second 138/69-kV transformer at Spring Green with a 100 MVA summer normal rating	2016	3	Was 2013; updated load/model information
Uprate X-67 Portage-Trienda 138-kV line to 373 MVA	2016	3	Was 2014; updated load/model information
Construct new 138-kV line from North Lake Geneva to South Lake Geneva Substation	2016	3	Was 2015; updated study results
Construct new 138-kV bus and install a 138/69-kV 100 MVA transformer at South Lake Geneva Substation	2016	3	Was 2015; updated study results

Table PR-23			
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2009 10-Year Assessment			
PROJECTS DEFERRED (continued)	**New date**	**Planning Zone**	**Reason for Deferral**
Install 2-16.33 MVAR 69-kV capacitor banks at Eden Substation	2016	3	Was 2014; updated load/model information
Install 4-49 MVAR 138-kV capacitor banks at Concord Substation	2016	3	Was 2011; updated load/model information
Replace two existing 138/69-kV transformers at Glenview Substation with 100 MVA transformers	2016	4	Was 2014; updated load/model information
Replace 138/69-kV transformer at Metomen Substation	2017	1	Was 2013; now a two-phased approach – breaker replaced in 2010, transformer in 2017
Uprate Y159 Brick Church-Walworth 69-kV line to 115 MVA	2017	3	Was 2015; updated load/model information
Construct a Lake Delton-Birchwood 138-kV line	2017	3	Was 2015; updated load/model information
Install 2-12.25 MVAR 69-kV capacitor banks at Mazomanie Substation	2017	3	Was 2014; updated load/model information
Construct a Horicon-East Beaver Dam 138-kV line	2019	3	Was 2014; updated load/model information
Install 2-32 Mvar capacitor banks at Mukwonago 138-kV Substation	2019	5	Was 2014; updated load/model information
Install 28.8 MVAR capacitor bank at Butternut 138-kV Substation	2020	4	Was 2016; updated load/model information
Uprate the Melissa-Tayco to 229 MVA (300F)	2020	4	Was 2016; updated load/model information
Install 138/69-kV transformer at Custer Substation	2020	4	Was 2016; updated load/model information
Construct Shoto to Custer 138-kV line	2020	4	Was 2016; updated load/model information
Rebuild/Convert Bayport-Suamico-Sobieski-Pioneer 69-kV line to 138 kV	2020	4	Was 2016; updated load/model information

Table PR-23			
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2009 10-Year Assessment			
PROJECTS DEFERRED (continued)	**New date**	**Planning Zone**	Reason for Deferral
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	2021	1	Was 2018; updated load/model information
Construct a 345-kV bus, install a 345/138-kV 500 MVA transformer at North Randolph and loop the Columbia to South Fond Du Lac 345-kV line into the substation	2021	3	Was 2018; updated load/model information
Install 2-16.33 Mvar 69-kV capacitor banks at Rio	2022	3	Was 2019; updated load/model information
OTHER PROJECT CHANGES AND POSSIBLE CHANGES	**Date**	**Planning Zone**	**Nature of Change or Update**
Install 1-8.2 MVAR capacitor bank at Hiawatha 138-kV Substation	2009	2	Was 16.33 MVAR capacitor bank
Uprate the Chandler-Delta #1 69-kV line summer emergency rating from 120 deg F to 167 deg F	2009	2	Was 2010 in-service date
Uprate the Chandler-Delta #2 69-kV line summer emergency rating to from 120 deg F 167 deg F	2009	2	Was 2010 in-service date
Replace Metomen 69-kV breaker	2010	1	Metomen xfmr project broken into two pieces; Phase I 2010 and Phase II 2017
Uprate X-23 Colley Road-Marine 138-kV line terminals	2010	3	Was 2014 in-service date
Construct second Shorewood-Humboldt 138-kV underground cable	2010	5	Was 2012 in-service date
Install 1-4.08 MVAR capacitor bank at North Bluff 69-kV Substation	2011	2	Was yet to be determined in-service date
Replace two overhead Blount-Ruskin 69-kV lines with one underground 69-kV line	2011	3	Was yet to be determined in-service date, provisional status now proposed

Table PR-23			
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2009 10-Year Assessment			
OTHER PROJECT CHANGES AND POSSIBLE CHANGES (continued)	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	Was yet to be determined in-service date
Rebuild part of the Y-8 Dane-Dam Heights 69-kV line	2012	3	Was 2015 in-service date; now combined with earlier maintenance project
Uprate Y-40 Gran Grae-Boscobel 69-kV line to achieve a 99 MVA summer emergency rating	2012	3	Was 2014 in-service date
Uprate Fitchburg-Nine Springs 69-kV and Royster-Pflaum 69-kV lines and move AGA load to the Royster-Femrite 69-kV line	2013	3	Was loop Nine Springs-Pflaum into Femrite
Construct second Dunn Road-Egg Harbor 69-kV line	2016	4	Was proposed status, now provisional
Uprate Castle Rock-Mckenna 69-kV line	2017	1	Was 2018 in-service date
NEW PROJECTS	In-Service Date	Planning Zone	Reason for Project
Uprate Point Beach-Sheboygan Energy Center 345-kV circuit L111 to 167 degrees F	2010	4	Market congestion
Rebuild/convert Straits-Pine River 138-kV lines 6904/5	2012	2	Upper Peninsula Collaborative study results
Install 138/69-kV 150 MVA transformer at Pine River	2012	2	Upper Peninsula Collaborative study results
Install 138/69-kV 150 MVA transformer at Nine Mile	2012	2	Upper Peninsula Collaborative study results
Install 138/69-kV 150 MVA transformer at Lakehead Rapid River	2012	2	Upper Peninsula Collaborative study results
Construct tap from the Kinross load to Pine River/Nine Mile 69-kV line	2012	2	Upper Peninsula Collaborative study results
Construct/convert Pine River-Nine Mile 138/69-kV double-circuit line	2012	2	Upper Peninsula Collaborative study results
Install second Chandler 138/69-kV transformer	2013	2	Upper Peninsula Collaborative study results
Install 2-16.33 MVAR 69-kV capacitor banks at Nine Springs Substation	2013	3	Upper Peninsula Collaborative study results

Table PR-23			
Summary of Cancellations, Deferrals, Changes, Possible Changes and New Projects for the 2009 10-Year Assessment			
NEW PROJECTS (continued)	In-Service Date	Planning Zone	Reason for Project
Uprate Munising-Seney-Blaney Park 69-kV line to 167 degrees F	2014	2	Upper Peninsula Collaborative study results
Construct Gwinn-Forsyth second 69-kV line	2014	2	Upper Peninsula Collaborative study results