

AMERICAN TRANSMISSION COMPANY

UPDATE 2003 10-YEAR TRANSMISSION SYSTEM ASSESSMENT

March 2004

Table of Contents

Page No.

Executive Summary	1
Section I – ATC’s Public Planning Process	5
Introduction.....	5
Transmission Planning Approach	6
ATC Planning Zones.....	9
Section II – Customer/Stakeholder Input.....	11
Introduction.....	11
Key Customer/Stakeholder Input.....	12
Changes/Additions to the 2004 Assessment.....	13
Section III – Status of Projects	15
Projects Completed During 2003.....	15
Projects Under Construction.....	17
Projects with Pending Applications.....	18
Project Applications to be Filed in 2004.....	18
Status of ATC Projects	20
Project Costs	22
Section IV – Changes to the 2003 10-Year Assessment.....	23
New Generation Projects	23
Fox Valley Generation.....	23
Weston Power Plant Expansion.....	23
Transmission Projects	24
Zone 1	24
Venus-Metonga-Laona 138 kV (operate at 115 kV) line	24
Rocky Run-Northpoint 115 kV line uprate.....	25
Eagle River-Cranberry/Three Lakes 115 kV line	25
Clear Lake-Arnett Road 115 kV line.....	25
Arrowhead-Weston construction plans.....	25
Arrowhead-Weston reactive support	26
Arrowhead-Weston midpoint substation	26
Zone 2	27
Stiles-Plains double circuit 138 kV line	27
Nordic-Randville Substation – rebuild single circuit 69 kV line to double circuit 69 kV.....	27
Zone 3	27
Rockdale-Boxelder 138 kV line	27
Jefferson-Lake Mills-Stony Brook 138 kV line.....	28
Construct Rubicon-Hustisford 138 kV line and rebuild Hustisford- Horicon 69 kV line to 138 kV (new)	28
Brooklyn-Belleville 69 kV line (now Brooklyn-Sugar River)	28
Sugar River Substation (new)	28
Sugar River-Southeast Fitchburg 138 kV line	28

Zone 4	29
Werner West-Clintonville 138 kV line	29
Erdman-Howards Grove 138 kV line	29
Equipment replacement at South Fond du Lac substation.....	29
Lodestar-Sheboygan Falls 138 kV line.....	29
Zone 5	30
Hartford 138 kV capacitor bank	30
Rockdale-Lannon Junction 345 kV line	30
System reinforcements for Elm Road generation	30
Oak Creek-Ramsey 138 kV line	31
Ramsey-Harbor 138 kV line	31
Oak Creek-Allerton 138 kV line.....	31
Oak Creek-Brookdale-Granville 345 kV line	31
Oak Creek-St. Martins 138 kV line	31
Bluemound-Butler 138 kV line.....	31
Butler-Tamarack 138 kV line	31
Brookdale 345/138 kV switchyard	31
Convert Oak Creek-Bluemound 230 kV line to 345 kV.....	31
Bluemound 345/138 kV switchyard	32
Oak Creek 345 kV switchyard expansion.....	32
345 kV breakers at Pleasant Prairie switchyard.....	32
Bluemound substation 138 kV breakers	32
Uprate Kansas-Ramsey 138 kV line	33
Uprate Oak Creek-Ramsey 138 kV line	33
Install second 345/138 kV transformer at Oak Creek.....	33
Additional Oak Creek 345 kV switchyard expansion.....	33
Bluemound 345 kV switchyard expansion	33
Convert Oak Creek-Bluemound 230 kV to 345 kV.....	33
Oak Creek-Racine 345 kV line	33
Harbor, Everett and Haymarket substation 138 kV breakers	34
Additional Oak Creek 345 kV switchyard expansion.....	34
Umbrella Plans.....	34
Northern Umbrella Plan (Phase 1).....	34

Section V – Updated Summary of Transmission System Facilities	51
Summary of Transmission System Additions 2004-2012	51
Need Categories.....	51

Section VI – Access	69
Background	69
Access Value Proposition	70
Preliminary Transfer Capability Analyses	73
□ Directional Analysis.....	73
□ Methodology	73
□ Key Assumptions	74
□ Description of Representative Proxy Projects	75
□ Network Analysis.....	76
□ MISO Flowgate Analysis.....	79
□ Combined Project Network Analysis.....	81
□ Conclusions – Directional Analysis.....	81
Appendix A Transmission-Distribution Interconnections - Updated.....	83
Appendix B Summary of Changes to the 2003 10-Year Assessment.....	89

Tables

Page No.

Table ES-1	Summary of ATC's 2003 Transmission System Assessment Update	2
Table III-1	Projects Completed since September 2003 10-Year Assessment	15
Table III-2	Project Applications to be Filed in 2004	18
Table V-1	Changes to the 2003 10-Year Assessment	53
Table V-2	Alternative Solutions to Planned, Proposed or Provisional Additions	59
Table VI-1	Costs and Import Capability for Each Representative Project.....	76
Table VI-2	Percent Impact of Transfer on MISO Monitored Flowgates (ATC only)	79
Table VI-3	Percent Impact of Transfer on MISO Monitored Flowgates (non-ATC)	80
Table VI-4	Costs and Import Capability From Combined Project Analysis.....	81

Figures

		Page No.
Figure ES-1	Transmission System Additions 2003-2012	3
Figure I-1	ATC Planning Zones.....	9
Figure III-1	Completed Projects since September 2003 10-Year Assessment.....	16
Figure III-2	Depiction of Project Applications to be Filed in 2004	19
Figure III-3	Number of Projects by Status (2001-2003 Update).....	21
Figure III-4	Cost of Projects by Status (2001-2003 Update).....	22
Figure IV-1	Northern Umbrella Plan.....	36
Figure IV-1-1	Northern Umbrella Plan 2005 Shoulder Peak, Existing System.....	41
Figure IV-1-2	Northern Umbrella Plan 2005 Shoulder Peak plus Project A (Phase 1)	42
Figure IV-1-3	Northern Umbrella Plan 2005 Shoulder Peak plus Projects A (Phase 1) and B	43
Figure IV-1-4	Northern Umbrella Plan 2006 Shoulder Peak plus Projects A (Phase 1) through D	44
Figure IV-1-5	Northern Umbrella Plan 2006 Shoulder Peak plus Projects A (Phase 1) through D, during construction outage of Project A (Phase 2)	45
Figure IV-1-6	Northern Umbrella Plan 2006 Shoulder Peak plus Projects A (Phases 1 and 2) and B through D.....	46
Figure IV-1-7	Northern Umbrella Plan 2007 Shoulder Peak plus Projects A through F	47
Figure IV-1-8	Northern Umbrella Plan 2007 Shoulder Peak plus Projects A through G	48
Figure IV-1-9	Northern Umbrella Plan 2008 Shoulder Peak plus Projects A through G and Arrowhead-Weston 345 kV line	49
Figure IV-1-10	Northern Umbrella Plan 2009 Shoulder Peak plus Projects A through H and Arrowhead-Weston 345 kV line	50
Figure V-1	Zone 1 – Transmission System Solution Alternatives.....	64
Figure V-2	Zone 2 – Transmission System Solution Alternatives	65
Figure V-3	Zone 3 – Transmission System Solution Alternatives	66
Figure V-4	Zone 4 – Transmission System Solution Alternatives	67
Figure V-5	Zone 5 – Transmission System Solution Alternatives.....	68
Figure VI-1	Representative Access Projects.....	75
Figure VI-2	Comparison of Representative Projects – Increased Import Capability for Each Scenario.....	77
Figure VI-3	Comparison of Representative Projects – Improved Import Capability vs. Project Costs.....	78
Figure VI-4	Comparison of Combined Major Alternatives	82
Figure A-1	Transmission-Distribution Interconnection Requests – Zone 1.....	84
Figure A-2	Transmission-Distribution Interconnection Requests – Zone 2.....	85
Figure A-3	Transmission-Distribution Interconnection Requests – Zone 3.....	86
Figure A-4	Transmission-Distribution Interconnection Requests – Zone 4.....	87
Figure A-5	Transmission-Distribution Interconnection Requests – Zone 5.....	88

EXECUTIVE SUMMARY

This report is the update to the 2003 10-Year Transmission System Assessment report issued in September 2003. The Assessment reports current results of planning activities and analyses of the transmission facilities owned and service territory encompassed by American Transmission Company LLC (ATC). These activities and analyses identify needs for transmission system enhancement and potential projects responsive to those needs. This 2003 update report describes changes to the 2003 10-Year Assessment through 2012 based on updated information provided by local distribution companies, the latest transmission service requirements and generation interconnection requests, recent analyses conducted by ATC, input from various stakeholders at ATC-sponsored meetings, and other developments.

The updated information in this report provides further foundation for continued public discussions on the transmission planning process, identified transmission needs and limitations, possible resolutions to those needs, and coordination with other public infrastructure planning processes.

In addition to providing updated need and project information, this report presents additional information on a topic introduced briefly in the September 2003 report that will become a key focus for discussion in 2004. This topic is “Access”, or the ability of customers connected to ATC’s system to gain greater access to lower cost energy and move it within the ATC system to where it is needed to serve energy requirements.

Based on anticipated changes to ATC's 10-year system expansion plan since the 2003 10-Year Assessment, this 2003 Update anticipates the following:

Table ES-1		
Summary of American Transmission Company's		
2003 Transmission System Assessment Update		
	2003 10-Year Assessment	2003 Update
	(September 2003)	(March 2004)
New Transmission Lines Requiring New Right-of-Way		
345 kV	8 lines / 220 miles	8 lines / 220 miles
138 kV	17 lines / 107 miles	14 lines / 80 miles
115 kV	4 lines / 42 miles	6 lines / 52 miles
69 kV	9 lines / 92 miles	8 lines / 84 miles
Transmission Lines to be Constructed, Rebuilt, Reconductored or Upgraded on Existing Right-of-Way		
345 kV	7 lines / 114 miles	8 lines / 168 miles
138 kV	47 lines / 807 miles	42 lines / 760 miles
115 kV	4 lines / 108 miles	4 lines / 98 miles
69 kV	12 lines / 54 miles	9 lines / 47 miles
New Transformers to be Installed		
(# of transformers / total capacity)	38 transformers / 9980 MVA	41 transformers / 9740 MVA
New Capacitor Banks to be Installed		
(# of installations / capacity)	34 installations / 930 MVAR	31 installations / 964 MVAR

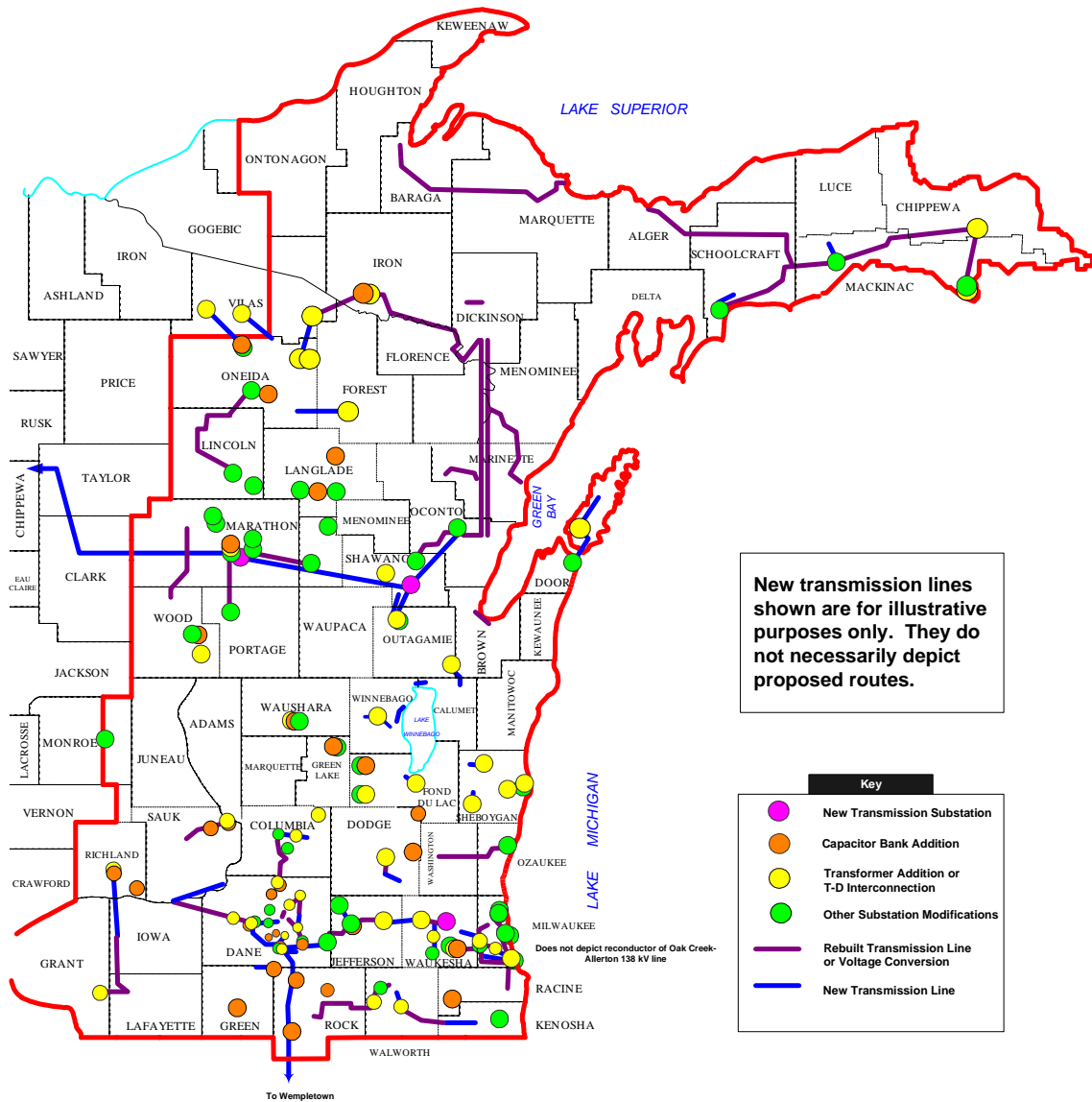
Details of the specific changes to ATC's plans from those listed in the September report are provided in Section IV of this Update; a summary of changes is provided in Appendix B. Several of the changes are due to proposed new generation projects meeting criteria for inclusion that will require the construction of new transmission facilities. Other changes are attributable to further analyses of project alternatives done by ATC. Still other changes are due to updated load forecast information provided by ATC customers.

Although this March 2004 Update illustrates various changes in the set of projects responsive to identified needs as compared to the September 2003 Assessment, the total estimated cost for projects reflected here is approximately the same as it was in the September report – now slightly over \$1.7 billion. At this time, ATC continues to anticipate total capital expenditures of around \$2.8 billion over the years 2003 through 2012. The difference in costs between this total expenditure and the \$1.7 billion for projects reflected in this document consists of costs for:

- Interconnection of proposed generation projects not yet meeting criteria for inclusion in this Update

- ❑ Possible transmission projects not yet included in the tables
- ❑ Transmission-distribution interconnections that don't require a regulatory filing or more than a few spans of transmission line construction
- ❑ Capital-related maintenance projects
 - ❑ Line rebuilds not involving reconductoring or voltage conversions
 - ❑ Circuit breaker, switch and other terminal equipment replacements
- ❑ Protective relay replacements

Figure ES-1
TRANSMISSION SYSTEM ADDITIONS
2003 THROUGH 2012
May be Planned, Proposed or Provisional



Section I

ATC's PUBLIC PLANNING PROCESS

Introduction

ATC's public planning process is a very important part of its overall operations. As discussed in more detail below, ATC performs extensive planning activities that take into account input provided through a wide variety of small and large meetings and interactions with utility customers, generators, state and federal regulators, and other interested stakeholders.

ATC has held Planning Zone meetings each year beginning in 2001 to describe its planning process and the information presented in the latest system assessment reports, and to solicit input on the process, needs, potential projects and associated right-of-way needs identified. The following Planning Zone meetings were held during 2003:

Zone 1	North-central Wisconsin	October 8	Wausau, Wis.
Zone 2	Upper Peninsula of Michigan and northern Wisconsin	September 24	Marquette, Mich.
Zone 3	South-central/southwest Wisconsin and South Beloit Illinois	October 9	Wisconsin Dells, Wis.
Zone 4	Northeast Wisconsin	September 25	Manitowoc, Wis.
Zone 5	Southeast Wisconsin	October 1	Port Washington, Wis.
All Zones		October 16	Oshkosh, Wis

At these meetings, stakeholders provided comments and expressed a wide range of opinions regarding the 2003 10-Year Assessment Report and information presented by ATC. This input has been summarized in this 2003 Update (see Section II) and is being taken into account in the development of 2004 activities.

While specific new transmission facilities are identified in this report to address certain needs and/or limitations, ATC will continue to solicit input on such proposed facilities from all interested parties before determining the ultimate solution for which ATC would pursue regulatory or other approvals. While several projects planned for the next few years are considered preferred alternatives by ATC, many projects planned beyond 2008, in general, should be considered as proxy solutions for resolving identified needs and as a basis for additional discussion and refinement.

The needs and limitations identified in this update are based on a current set of operational conditions, growth forecasts, proposed new generation and load interconnections, technical analyses, and customer and stakeholder inputs. Over time, new needs will be identified and other needs may change. Transmission system

conditions are fluid, and it is recognized that the transmission planning process must be able to respond to and incorporate changing needs and conditions. This process is iterative by nature, and with this assessment the ongoing cycle of needs identification, analysis, public input and solution development continues.

Transmission Planning Approach

The fundamental underpinnings of ATC's approach to transmission planning are customer need and public input. ATC intends to propose transmission options to resolve customer needs as expressed through:

- ❑ Load growth forecasts
- ❑ New load interconnection requests
- ❑ Long-term transmission service requests
- ❑ Generation interconnection requests
- ❑ Need for improved operational reliability
- ❑ Need for resolution of local and regional congestion and access to regional energy markets
- ❑ Need for replacement of old facilities
- ❑ Need for increased operational efficiency

To facilitate acceptance and implementation of any proposed plans, ATC believes the public, including all stakeholders, must be invited to participate in an open, iterative, and interactive public planning process.

To design the most efficient and effective ways of meeting customer needs, ATC has developed a process encompassing four levels of planning:

- ❑ Base – Localized Issue
- ❑ Second – ATC Planning Zone
- ❑ Third – ATC System
- ❑ Fourth – Regional/National

Needs and potential solutions are developed at each level and then vetted against those at the next level, until the most effective overall plans addressing the combined needs are developed. ATC performs the first three levels of planning for its area, and then works with Midwest Independent System Operator (MISO) to incorporate resolution of fourth-level issues identified through the broader regional planning process led by MISO. ATC is also an active participant in Mid-America Interconnected Network (MAIN) and North American Electric Reliability Council (NERC) reliability assessments of regional and eastern interconnection transmission systems.

The results of ATC's ongoing planning activities are presented in its 10-Year Transmission System Assessment reports, issued approximately every six months to respond to the most current mix of needs and issues. The purpose of these reports is to illustrate identified needs and potential solutions and provide the foundation for public discussion and participation in shaping the ultimate plans to be proposed. ATC then holds public meetings and other communication activities to inform and interact with interested stakeholders, including customers, public officials, regulators, environmental groups and other members of the public. The purpose of these meetings is to present identified needs and justification for projects in each area, facilitate identification of the most acceptable

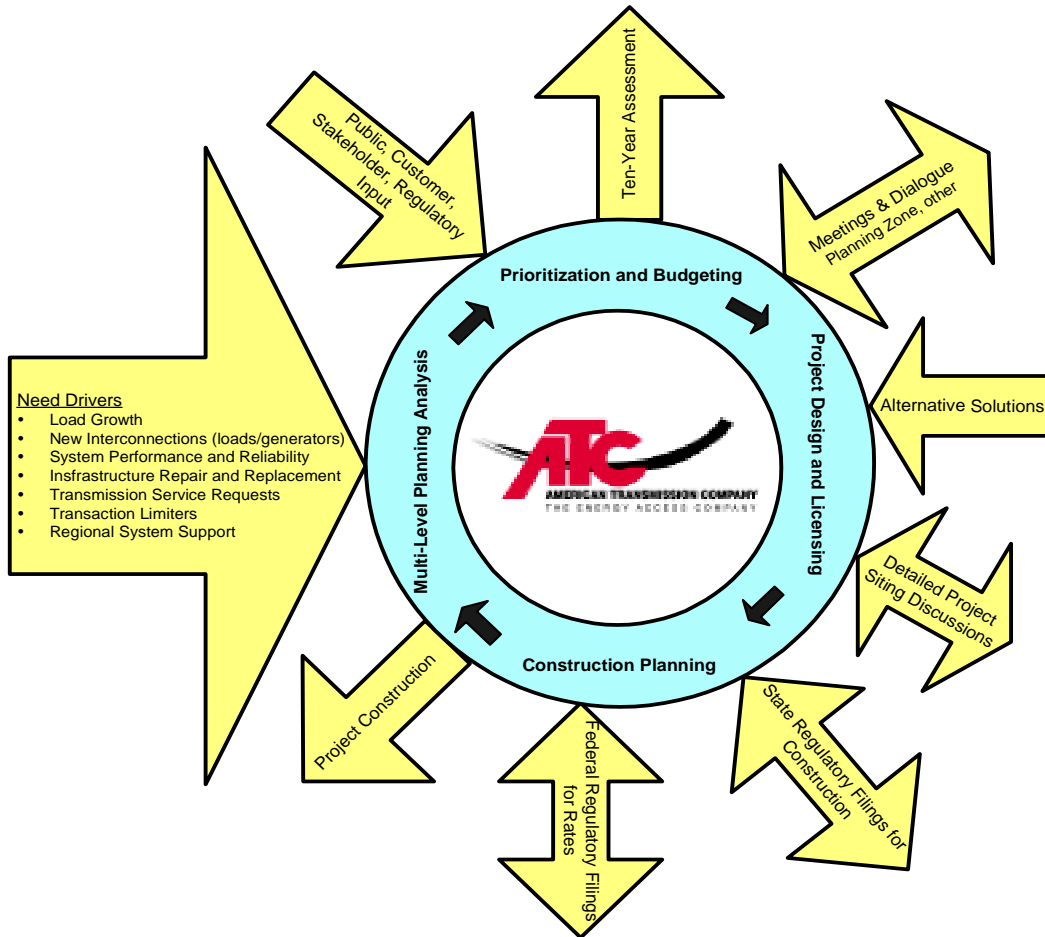
routes for any new transmission lines, allow for development and consideration of any additional alternatives that interested entities may want to propose to address identified needs, and receive public input to incorporate into future revisions of proposed plans. Communications activities are ongoing as the overall planning process continues through subsequent iterations.

The planning, permitting and construction cycle for transmission solutions require more time than what is required for most other alternative solutions. If identified needs are addressed effectively through alternative solutions, ATC will defer or cancel proposed transmission projects. If the needs remain, ATC will proceed with its projects, which have been effectively tailored through this iterative public input process. Public communication and discussion related to specific projects become more focused and targeted as necessary regulatory filing dates approach.

ATC strives to achieve its objectives of providing reliable service and an adequate transmission infrastructure to meet its customers' needs. This planning approach will make this achievement possible by facilitating development of the most effective mix of projects to meet those needs in a timely fashion. Public participation in this process is vital to its success, as the best plans provide no value or benefit unless they can actually be implemented, and implemented in time. Communicating openly, early and often is the best way to achieve public awareness and acceptance of needs and solutions, and to illustrate responsiveness to public concerns, which may otherwise prevent or delay necessary projects.

The figure below depicts ATC's planning process. The blue circle represents ongoing, continuous core ATC activities. Against that backdrop, there are constantly changing inputs and outputs that affect and shape the core activities, and ensure that ultimate project construction is responsive to the current mix of needs and influences.

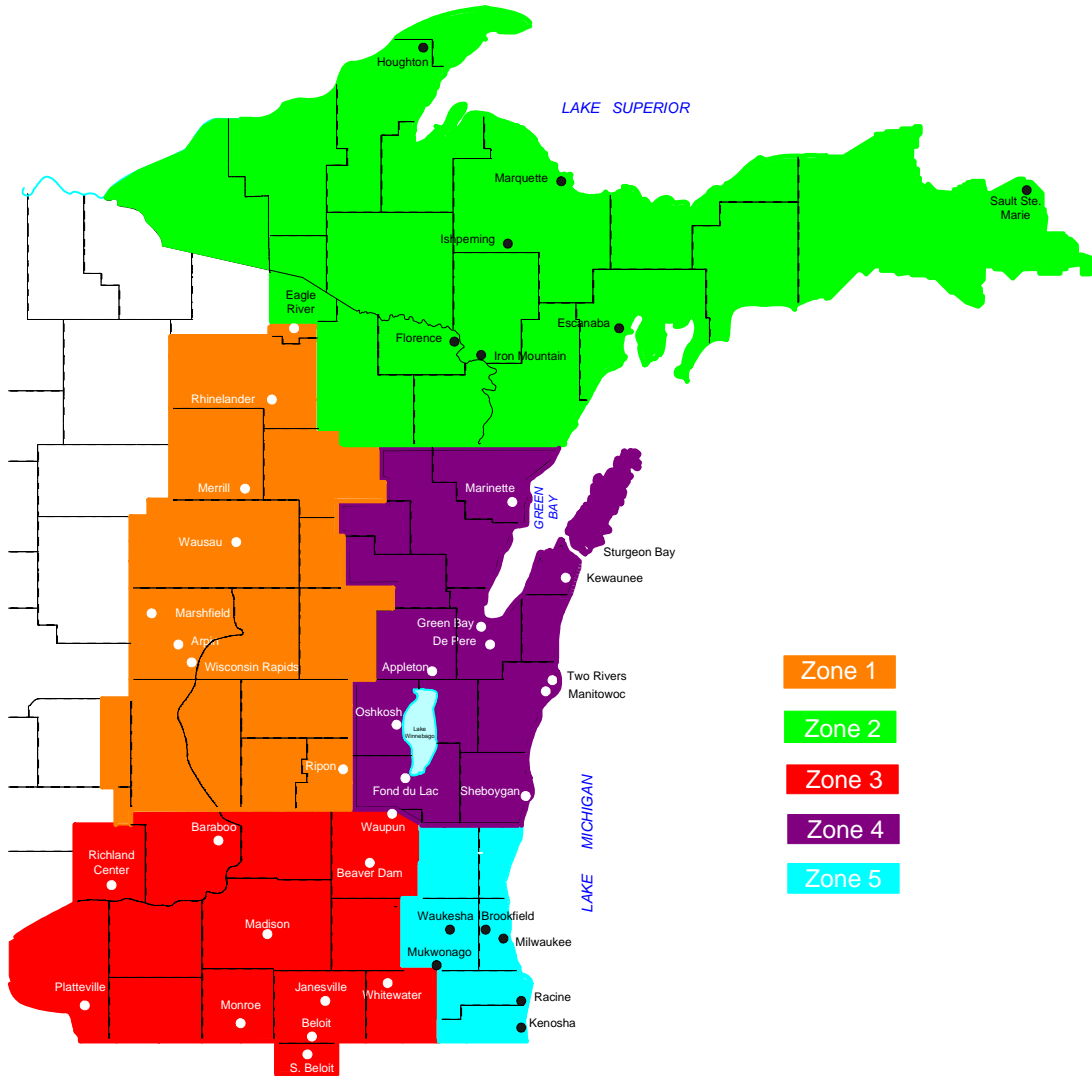
ATC's Public Planning Process



ATC Planning Zones

ATC utilizes the concept of planning zones in its Assessments of the transmission system within its service territory. Five planning zones have been defined representing distinct areas where needs are compiled and assessed. As described on page 5, zone level planning is one of four levels at which transmission system needs are assessed.

**Figure I-1
ATC Planning Zones**



Section II

CUSTOMER AND STAKEHOLDER INPUT

Introduction

As described in Section I, ATC held annual planning zone meetings during the fall of 2003 to describe the 2003 10-Year Assessment and to solicit feedback on ATC's public planning process. In addition, ATC has received additional comments on the 2003 10-Year Assessment from a number of customers and stakeholders. This section summarizes the feedback received from the planning zone meetings and from ATC customers. While ATC acknowledges the supportive or complimentary comments received and will strive to continue to do those things that our customers or stakeholders indicated are valuable, the focus of feedback solicitation is on suggestions for improving the reports or the meetings themselves.

At the planning zone meetings, ATC staff facilitated breakout sessions with smaller groups to solicit responses to the following questions:

TOPIC 1: YOUR LOCAL ZONE – WHAT ELSE SHOULD WE KNOW?

Given that the information presented is only a small part of all that could be used to describe your local area,

- What is your reaction to the zone description information presented?*
- What do the implications seem to be?*
- Are those implications the right ones or does part of the story seem to be missing?*
- What else is important for us to know about your zone or about working with the people and businesses in it perhaps compared to other zones?*
- What is most important to you as a resident/business in this zone with respect to transmission?*

TOPIC 2: REACTION TO TRANSMISSION PROJECTS

- What is your overall reaction to the projects presented here today?*
- Do you have any specific comments on or issues with any projects?*
- What other kinds of information/activities would you like to see as part of the transmission planning process?*
- What kind of questions should we be asking you, and when?*

In addition, ATC solicited comments via comment cards and meeting evaluation forms. Key suggestions from all of these sources have been incorporated into the following summary.

Key Customer/Stakeholder Input

Focus on audience

- ❑ Consider separate, more tailored meetings and communications to encourage greater participation from all stakeholders including the general public and industrial customers that are large consumers of electricity.

Active information sharing

- ❑ Make coordination with local entities a priority in the planning and project processes.
- ❑ Consider regional/county/town planning organizations, local government, local business, industry and economic development groups, and Smart Growth plans.
- ❑ Hold public meetings to discuss planning process.

Economic information

- ❑ Discuss project costs in more detail.
- ❑ Communicate ATC's place in the energy industry.
- ❑ Explain ATC's rate structure and the impact of projects on rates.
- ❑ Explain the short- and long-term effects of the existence and activities of ATC.

Public education

- ❑ Educate the public on the needs of the transmission system.
- ❑ Correlate electrical demands of modern living with the reliability of the transmission system.
- ❑ Make the case that attracting new industry depends in part on reliable and cost-effective electric service, and describe the role of the transmission system in achieving that.

Corridor sharing

- ❑ Lessen environmental impacts.
- ❑ Coordinate with local development plans.
- ❑ Seek project cost savings.

Environmental impacts

- ❑ Provide more information on how ATC evaluates the environmental impacts of its projects.
- ❑ For major projects, develop communication materials to describe environmental considerations, decisions and actions.

Project Planning and Decision Processes

- ❑ Describe solution-screening process.
- ❑ Discuss alternatives considered.
- ❑ Explain how projects move from concepts to firm plans.
- ❑ Get the attention of the public on industry issues and seek involvement.

Planning zone meeting format

- ❑ Continue use of slides and PowerWorld.
- ❑ Continue interactive format.

Changes/Additions to the 2004 Assessment

Based on the comments received from stakeholders and customers, ATC plans to incorporate the following changes and additions to the 2004 Assessment:

- ❑ Provide information related to increasing access for customers
- ❑ Enhance the information provided regarding generation redispatch costs
- ❑ Address the issue of lost opportunity costs (for energy transactions) due to transmission limitations
- ❑ Provide geographical references to substation names
- ❑ Incorporate findings from more detailed dynamic stability analyses

In addition, ATC will be modifying its approach to the planning meetings for 2004 based on comments received, and will also be hosting various meetings to discuss the “Access” topic. Additional feedback and suggestions regarding ATC planning reports and meetings are welcome at any time and can be sent to planning@atcllc.com.

Section III

STATUS OF PROJECTS

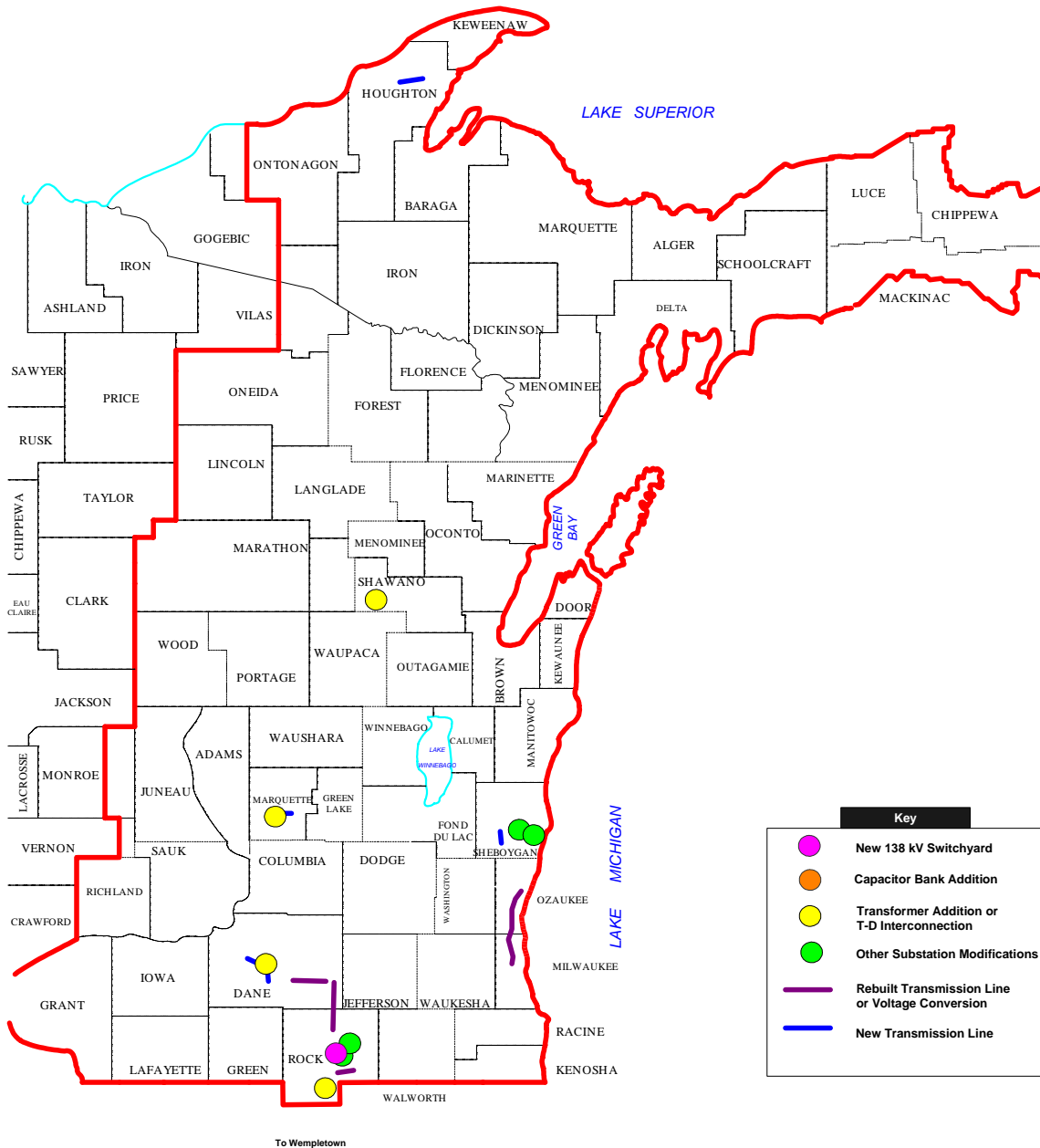
This section identifies transmission projects that were completed in 2003, are under construction or are in the approval stage. This section also provides a list of projects that ATC expects to file a construction application for during 2004. In addition, ATC has compiled a list of major projects constructed and/or contemplated since 2001. In this section, the status of those projects is shown graphically.

*Table III-1
Projects Completed Since September 2003 10-Year Assessment*

Reference Number	Completed Additions	Planning Zone
1	Construct an Endeavor-Wautoma/Portage Tap 69 kV line	1
2	Uprate Whitcomb 115/69 kV transformer	1
3	Construct Elevation Tap-Elevation 69 kV line	2
4	Reconductor Christiana-Kegonsa portion of Christiana to Fitchburg 138 kV line	3
5	Reconfigure 69/138 kV circuits between Rock River and Janesville to create Rock River-Janesville and Rock River-Sunrise 138 kV circuits	3
6	Reconductor Colley Road-Blackhawk 138 kV line	3
7	Construct 138 kV switchyard at Riverside generation site (Townline Road Substation)	3
8	Construct 138 kV double circuit line from Townline Road to Rock River	3
9	Reconnect NW Beloit 69 kV load to Paddock-Blackhawk 138 kV line	3
10	Replace 200 A metering CT at Sheboygan Falls 69 kV	4
11	Retap metering CT at Lodestar 138 kV	4
12	Construct 138 kV line from Mullet River to N Mullet River and convert N Mullet River to Plymouth Sub #1 from 69 kV to 138 kV	4
13	Construct 69 kV switchyard at Tokay	3
14	Construct Fitchburg-Tokay-West Towne 69 kV underground line	3
15	Reconductor Russell-Rockdale 138 kV line	3
16	Rebuild Port Washington-Range Line double circuit 138 kV line	5

Five of the projects above were needed in order to accommodate new generation (#5, 7, 8 and 15 relate to the Riverside generation and #16 relate to the Port Washington generation). Four other projects were needed to accommodate T-D interconnection requests (#1, 3, 13 and 14). The Fitchburg-Tokay-West Towne line also provides additional reliability benefits. Two projects were needed to address chronic transmission service limitations (#4 and 6). The remaining projects (#2, 10, 11 and 12) were needed to address reliability issues.

**Figure III-1
COMPLETED PROJECTS SINCE
SEPTEMBER 2003 10-YEAR ASSESSMENT**



Projects Under Construction

ATC is currently constructing or is planning construction on several projects:

Projects Currently Under Construction

Convert Pine-Grandfather-Tomahawk-Eastom 46 kV lines to 115 kV
Construct an Omro Industrial-Berlin/Omro 69 kV line
Move Reedsburg 6 MVA D-SMES unit to Clear Lake 115 kV
Uprate North Randolph-Ripon 69 kV line terminal equipment
Install 4.1 MVAR capacitor bank at Ripon 69 kV
Install additional 4.1 MVAR capacitor bank at Berlin 69 kV
Rebuild Skanawan-Highway 8 115 kV line to double circuit 115 kV
Construct Stone Lake-Arrowhead 345 kV line
Construct Hiawatha-Engadine 69 kV line
Expand Indian Lake 69 kV to accommodate Indian Lake-Glen Jenks 69 kV line
Rebuild from Nordic SS to Randville SS (5 miles) of single circuit 69 kV line to double circuit 69 kV
Rebuild Indian Lake to Glen Jenks to four circuits - two 138 kV, two 69 kV
Uprate Cedar-Freeman 138 kV line
Uprate Cedar-M38 138 kV line
Uprate Freeman-Presque Isle 138 kV line
Uprate Presque Isle-Cedar 138 kV line
Rebuild and convert one Hiawatha-Indian Lake 69 kV circuit to double circuit 138 kV standards, string one circuit initially and operate at 69 kV
Reconfigure 69/138 kV circuits between Rock River and Janesville to create Rock River-Janesville and Rock River-Sunrise 138 kV circuits
Convert Kilbourn-Zobel 69 kV line to 138 kV
Replace the existing 187 MVA 138/69 kV transformer at Sycamore with two 100 MVA transformers and reconfigure 138 kV bus
Rebuild Russell-Janesville 138 kV line
Install a second 138/69 kV transformer at North Randolph
Install 24 MVAR capacitor bank at new Birchwood 138 kV
Rebuild Femrite-Royster 69 kV line
Install 16.32 MVAR capacitor bank at Lone Rock
Expand Walnut Substation to interconnect West Campus generation
Install 16.3 MVAR capacitor bank at Kegonsa 69 kV
Install 20.4 MVAR capacitor bank at North Madison 69 kV
Install 24.5 MVAR capacitor bank at Cross Country 138 kV
Install 12.2 MVAR capacitor bank at Waunakee 69 kV
Install 7.2 MVAR capacitor banks on distribution system at/near Tokay
Install 7.2 MVAR capacitor banks on distribution system at/near West Middleton
Replace 200 A metering CT at Sheboygan Falls 69 kV
Retap metering CT at Lodestar 138 kV
Construct/rebuild double circuit 138/69 kV line from Pulliam to Bayport
Rebuild the Morgan-Falls-Pioneer-Stiles 138 kV line

Projects Currently Under Construction (continued)

Install 345 kV breaker for Edgewater 345/138 kV transformer (TR-22)
Replace two 800 A line traps at Edgewater 138 kV
Construct a tap to Belle Plain from the Badger-Caroline 115 kV line
Construct new Fox Energy switchyard
Construct a Fox Energy-Forest Junction 345 kV line
Rebuild Port Washington-Saukville double circuit 138 kV line
Rebuild Port Washington-Saukville single circuit 138 kV line

Projects with Pending Applications

ATC has filed either CA or CPCN applications with the Wisconsin Public Service Commission requesting authority to construct several projects. Those projects that are awaiting a PSC order are listed below:

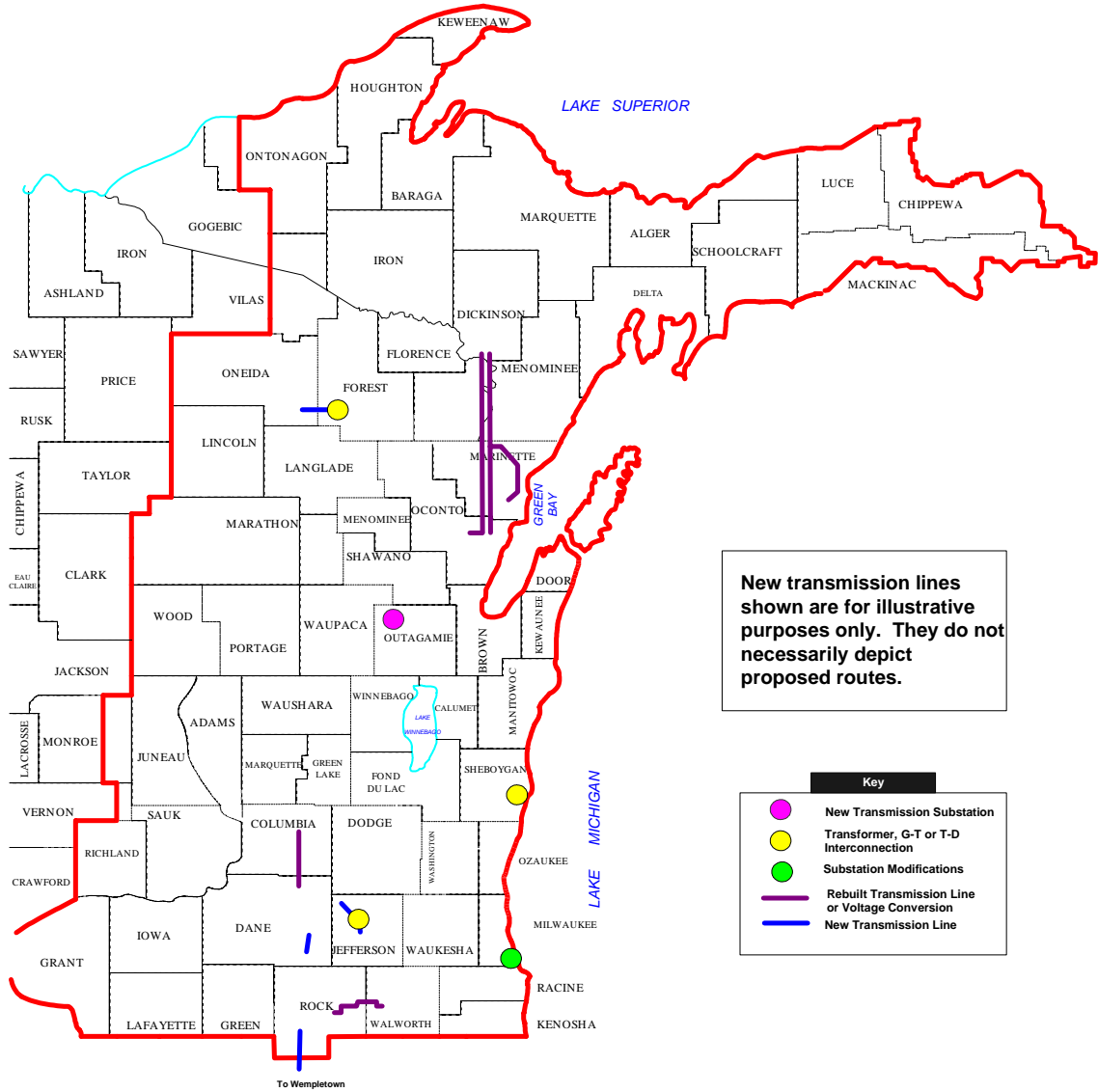
- ❑ Rebuild existing West Marinette-Menominee 69 kV line to double circuit 138/69 kV
- ❑ Convert Menominee-Rosebush 69 kV line to 138 kV
- ❑ Rebuild/reconductor Rosebush-Amberg 138 kV line
- ❑ Uprate Stiles-Plains double circuit 138 kV line
- ❑ Construct new line from West Darien to Southwest Delavan to Delavan at 138 kV, operate at 69 kV
- ❑ Construct 138 kV bus at Kegonsa and terminate both Christiana-Fitchburg circuits into Kegonsa

Project Applications to be filed in 2004

**Table III-2
Project Applications to be filed in 2004**

<i>CPCN Applications</i>
Columbia-North Madison 138 kV line conversion to 345 kV
Wempletown-Paddock 345 kV line
Femrite-Sprecher 138 kV line
Jefferson-Lake Mills-Stony Brook 138 kV line
Venus-Metonga 115 kV line
Elm Road generating station 138 kV line relocations and substation improvements
Sheboygan Energy Center Interconnection
Southwest Delavan-Delavan-Bristol 138 kV line
<i>CA Applications</i>
Plains-Stiles 138 kV line rebuild, Amberg-White Rapids 138 kV line rebuild and White Rapids-West Marinette 69 kV line rebuild and conversion to 138 kV
Morgan-Falls-Pioneer-Stiles 138 kV line rebuild
Werner West 345/138 kV substation
Turtle-West Darien 69 kV line rebuild to 138 kV standards

**Figure III-2
CA OR CPCN PROJECTS
TO BE FILED by ATC IN 2004**



Status of ATC Projects

In ATC's Assessments and Updates, projects are identified that address reliability issues, transmission service issues, generation interconnections or some distribution interconnections, or a combination of two or more of the above. In general, these projects address system performance issues per governing system planning criteria. ATC has numerous other projects underway or under evaluation that address other issues, including obsolete substation equipment, line facilities in poor condition, line relocations and most distribution interconnections. The projects referenced below include only those projects that address system performance issues.

To facilitate an understanding of the status of the various future projects, ATC developed project status designations for its 2003 10-Year Assessment: *Planned*, *Proposed* and *Provisional* (formerly *conceptual*).

Planned projects:

- ❑ planning is complete
- ❑ regulatory approvals, if required, have been applied for and are pending or have been issued
- ❑ may be under construction or in construction planning phase
- ❑ typically included in power flow models used to analyze transmission service requests

Proposed projects:

- ❑ planning is not complete
- ❑ regulatory approvals have not yet been sought
- ❑ represents ATC's preliminary preferred project alternatives from a system performance perspective
- ❑ typically not included in power flow models used to analyze transmission service requests

Provisional projects:

- ❑ planning is not complete
- ❑ regulatory approvals have not been sought
- ❑ does not necessarily represent ATC's preliminary preferred project alternative but reflects a placeholder project designation
- ❑ not included in power flow models used to analyze transmission service requests

In its 2001-2003 10-Year Assessments and Updates, ATC identified or assumed responsibility for approximately 350 projects that address system performance issues. Figure III-3 below illustrates the status of all Planned and Proposed projects. Regarding Figure III-3, it is worthwhile to note that:

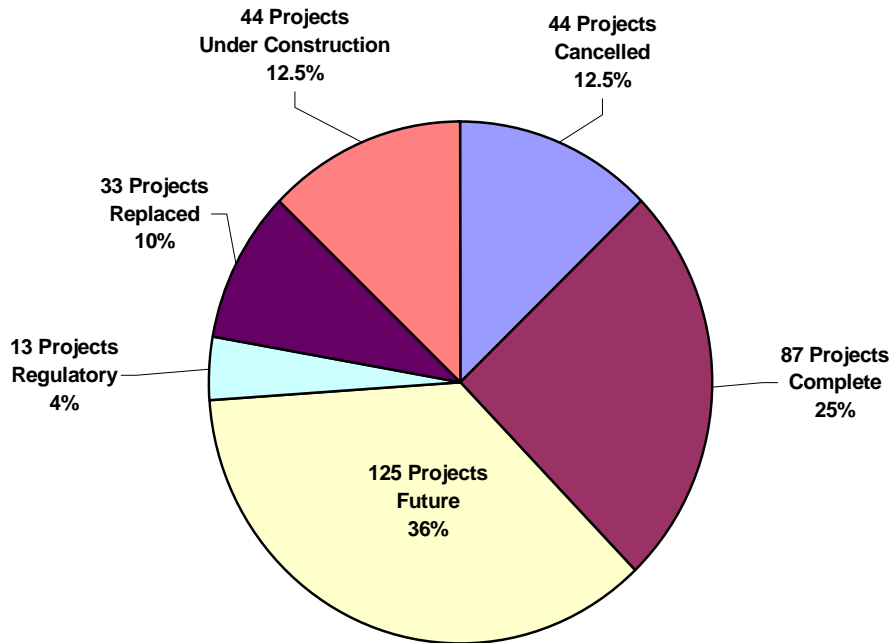
- ❑ ATC has completed 87 projects and another 44 are under construction. Notable projects most recently completed are listed earlier in this section. Projects under

construction range from capacitor bank installations to the Arrowhead-Weston transmission line project.

- ❑ Over 30 projects have been replaced with alternate project solutions. It is not unusual that the status of certain projects will change or evolve since customer needs and uses of the transmission system are continually changing.
- ❑ ATC canceled 44 projects that were identified in previous Assessment reports. Due to changing needs and up-to-date information, these projects were determined not to be needed. Most of these projects were relatively minor projects, involving only replacement of equipment at existing substations.
- ❑ ATC revised the scope of over 30 projects that were identified in previous Assessment reports. This is typically due to changing needs and system conditions.
- ❑ Approximately 125 future projects are in various stages of evaluation or development (Planned or Proposed).

Figure III-3

*American Transmission Company - Number of Projects by Status
10-Year Assessments 2001-2003 Update
Planned and Proposed Projects*

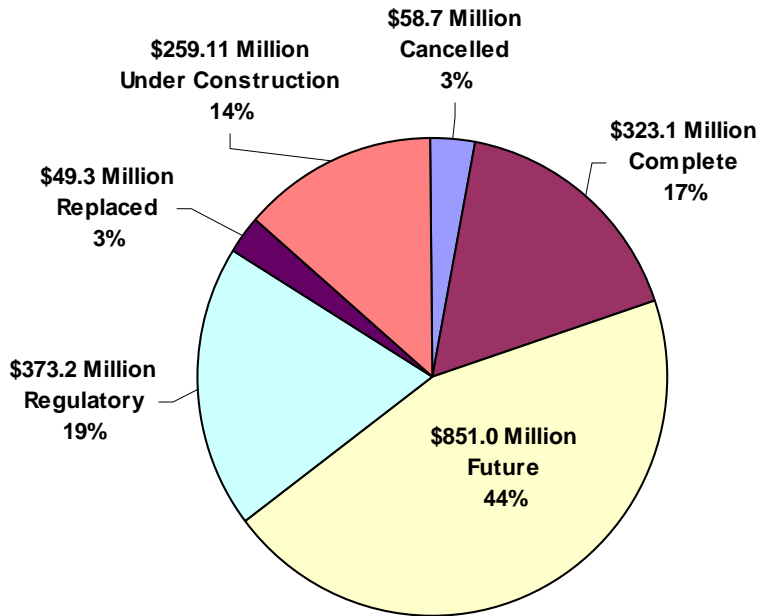


Project Costs

The estimated capital costs for all of the projects reflected in Figure III-3 are shown in Figure III-4. This figure shows that the combined capital costs for projects that are completed, canceled, replaced, in licensing and under construction account for roughly 56% of the estimated total capital costs, with future projects accounting for the remaining 44%. The estimated capital costs depicted in Figure III-4 are based only on those projects listed in the previous Assessments that affect system performance. The total estimated capital cost of those projects as reported in the 2003 10-Year Assessment was approximately \$1.7 billion. Other anticipated projects, including substation equipment replacements, pole and conductor replacements, most T-D interconnections, road relocations and generation interconnections not included in the 2003 10-Year Assessment, make up the remaining \$1.1 billion of the \$2.8 billion in capital expenditures that ATC projects over the next ten years. The cost estimates included in the below figure do not include estimates for Provisional projects from the 2003 10-Year Assessment and Update.

Figure III-4

*American Transmission Company - Cost of Projects by Status
10-Year Assessments 2001-2003 Update
Planned and Proposed Projects*



Section IV

CHANGES TO THE 2003 10-YEAR ASSESSMENT

This section describes the changes made by ATC to certain planned, proposed and provisional transmission projects since the 2003 10-Year Assessment was issued. These changes are based on regulatory actions and updated information provided by the local distribution companies, the latest transmission service requirements, interconnection requests, recent analyses conducted by ATC, and input from various stakeholders at ATC-sponsored meetings.

New Generation Projects

In its 2003 10-Year Assessment, ATC utilized the following criteria to establish which proposed new generation would be included in the power flow analyses conducted:

Those generation projects for which, at the time the models were developed, (i) ATC has completed a generation interconnection study, a transmission service impact study and, if required, a transmission service facility study, and (ii) the generation developer or a customer of the developer has accepted the transmission service approved by ATC.

Since the 2003 10-Year Assessment, the following two new generation projects have met the criterion above and are included in the 2004 Assessment.

Fox Valley Generation

A new power plant is under construction near Kaukauna (Zone 4). This project was approved by the Wisconsin Public Service Commission for a total of 670 megawatts. By June 2005, the developer is currently projecting to install 350-400 megawatts of generating capacity. Interconnection studies have been completed for both the 350-400 megawatts of capacity in 2005 and the ultimate 670-megawatt development. A transmission service study for 235 megawatts of the plant output has been completed, and the requested service approved and accepted. The following transmission facilities will be constructed by ATC to support this new generation:

- A new 345 kV switchyard located at the power plant site to connect the two generators and to connect three 345 kV lines
- Loop the existing Point Beach-North Appleton 345 kV line into the new switchyard
- A new 11-mile, 345 kV line from the power plant site to Forest Junction substation, utilizing approximately 8 miles of unused 345 kV line on existing right-of-way between the plant site and Forest Junction.

Weston Power Plant Expansion

A new 500-megawatt generator (Weston 4) has been proposed at the existing Weston Power Plant site near Wausau (Zone 1). This generator is projected to be in service in 2008. ATC has conducted interconnection studies and transmission service studies to

determine the impact of the generator on the transmission system. The results indicate that a new 345 kV line from Weston is needed and that various lower voltage lines need to be upgraded. In addition, the study results indicate that the Arrowhead-Weston 345 kV line is needed in addition to the required reinforcements above. Additional details on the transmission requirements for this generator are provided later in this section.

Based on the results of the studies, ATC is proposing that the transmission projects listed below be constructed. Appropriate applications to the Wisconsin PSC will be developed and submitted during the next two years.

- ❑ Construct a new 345 kV line from the Gardner Park substation to a new substation, currently called Central Wisconsin, located near the midpoint of the proposed Morgan-Werner West 345 kV line. ATC is proposing to license, construct and put this line in service by December 2009.
- ❑ Upgrade the Weston-Kelly 115 kV line by 2009.

The scheduled in service date for the new Weston 500-megawatt generator is June 2008 and the projected in service date for the Gardner Park-Central Wisconsin 345 kV line is December 2009. Based on the 18-month in service date difference between the generator and 345 kV line project, additional studies were performed to determine if any feasible projects exist for delivery of all or a portion of the 500 megawatts prior to the in service date of the above 345 kV project. The interim transmission service and generator interconnection studies identified the following projects that will allow the generator to operate during this interim period under certain operating limitations and restrictions. Full generator operation will not be allowed until all necessary 345 kV lines are placed in service.

- ❑ Rebuild/reconductor Weston-Northpoint 115 kV line
- ❑ Upgrade Northpoint-Rocky Run 115 kV line
- ❑ Upgrade Weston-Sherman St. 115 kV line
- ❑ Upgrade Weston-Morrison Ave.-Sherman St. 115 kV line
- ❑ Upgrade Weston-Kelly 115 kV line
- ❑ Upgrade Kelly-Whitcomb 115 kV line
- ❑ Upgrade Whiting Avenue-Plover 115 kV line

Transmission Projects

Zone 1

Venus-Metonga-Laona 138 kV (operate at 115 kV) Line

This project was proposed in response to a request by WPS for new distribution (T-D) interconnections at Metonga and Laona. Based on further analysis by WPS, the in service date of Metonga has been deferred from 2005 to 2007. In addition, WPS has proposed to site the Metonga substation on the east side of Crandon and expand the substation to include two distribution transformers. This will provide the ability to serve both the

Crandon and Laona areas with a single distribution substation and allow the flexibility to withdraw the Laona substation T-D interconnection request.

Rocky Run-Northpoint 115 kV line uprate

This project is proposed to reduce the number of Transmission Loading Relief (TLR) incidents called during the outage of the Weston-Rocky Run 345 kV line by replacing substation equipment at Northpoint with higher-rated equipment. This line segment is one of the initial limiters consistently identified in system impact studies in response to requests for transmission service. Therefore, by replacing the disconnect switches, this project will allow for the approval of additional transmission service.

Eagle River-Cranberry/Three Lakes 115 kV line

This proposed project interconnects a new Eagle River Light and Water substation currently being called Eagle River. The in service year for this project has been deferred from 2005 to 2006 to reflect a more realistic in service date given the precertification activities that will be undertaken.

Clear Lake-Arnett Road 115 kV line

This proposed project interconnects a new WPS T-D substation, Arnett Road. The in service year for this project has been deferred from 2005 to 2007 due to the additional time and resources required to perform precertification work for this new line on new right-of-way.

Arrowhead-Weston construction plans

Gardner Park Substation

Two major projects to be interconnected at Weston (the planned Arrowhead-Weston 345 kV line and a proposed new 500-megawatt generator) will require that substation facilities at Weston be expanded. After extensive evaluation of the existing substation facilities at Weston, ATC has determined that a new 345/115 kV substation on the Weston power plant site is the most feasible course of action. This new substation will be tied to the existing 115 kV switchyard at Weston via two new 115 kV circuits.

The Arrowhead-Weston project will initially require the development of the following 345 kV substation facilities at the new Gardner Park substation:

- A new four-position 345 kV ring bus to accommodate the new Arrowhead-Weston 345 kV line
- The existing Weston-Rocky Run 345 kV line
- Two new 500 MVA, 345/115 kV transformers

The Arrowhead-Weston project also will require the installation of 115 kV substation facilities to accommodate the two 345/115 kV transformers, two 115 kV lines connecting the existing Weston 115 kV substation to the new Gardner Park substation, and one of the existing 115 kV lines currently terminated at the existing 115 kV Weston bus. Power flow studies have indicated that moving either the Weston-Kelly 115 kV line or the Weston-Blackbrook 115 kV line to the new Gardner Park substation provides the optimum network benefits. Physical line routing constraints around the existing Weston

substation will determine which of these two lines will be relocated to the Gardner Park substation.

The proposed 500-megawatt generator addition at the Weston Power Plant will require the expansion of the initial 345 kV substation facilities described above, including two new 345 kV bus positions to accommodate the 345 kV leads from the generator and a new 345 kV line to the Central Wisconsin substation (see below). To summarize, this substation will allow ATC to interconnect lines and generators in the most logical fashion in light of the major project additions.

Arrowhead-Weston reactive support

In the 2003 10-Year Assessment, ATC initially specified that the following capacitor banks would be needed to support the transfer capability target associated with the Arrowhead-Weston project:

- Two 25 MVAR capacitor banks at Arpin 138 kV
- Two 25 MVAR capacitor banks at Arpin 115 kV
- Two 40 MVAR capacitor banks at Weston 115 kV
- Three 52 MVAR capacitor banks at Rocky Run 115 kV
- One 65 MVAR capacitor bank at Arrowhead 230 kV

Since the release of the 2003 10-Year Assessment, ATC has revisited the reactive support for the Arrowhead-Weston line in an effort to optimize the capacitor requirements. Both steady state and voltage stability studies are ongoing with the preliminary results indicating a change in size and placement of the capacitors including:

- Six 34 MVAR capacitor banks at Gardner Park 115 kV
- One 40 MVAR capacitor banks at Arpin 138 kV
- Four 50 MVAR capacitor banks at Arrowhead 230 kV

The sizes and locations of these capacitor bank installations will change depending on whether the existing Stone Lake 161 kV substation is expanded to accommodate capacitor banks. Studies done to date indicate that locating capacitors at Stone Lake would be more effective, and thus reduce the overall reactive requirements at Arrowhead and Gardner Park.

Arrowhead-Weston midpoint substation

ATC is considering several potential applications for making temporary expansion of the Stone Lake substation permanent. As noted above, a 345/161 kV transformer will be installed at Stone Lake during construction of the northern portion of the Arrowhead-Weston line to support the system during the outage of the Stone Lake-Stinson 161 kV line. Other potential applications include installation of capacitor banks and an inductor bank for both switching and operating the Arrowhead-Weston line.

Whether the 345/161 kV transformer becomes permanent may be driven by either of two factors:

- The benefits of interconnection to the Xcel Energy and Dairyland Power Cooperative facilities at Stone Lake, and

- The benefits of installing 161 kV capacitor banks at Stone Lake, either with or without the interconnection to the Xcel Energy and Dairyland Power Cooperative facilities.

ATC believes there is considerable benefit to installing capacitor banks and inductor banks at Stone Lake. As noted above, installing capacitor banks at Stone Lake provides more effective reactive support than comparable amounts at Arrowhead and/or Gardner Park. Installing an inductor bank at Stone Lake is more beneficial for switching and operating Arrowhead-Weston than a comparable bank at Gardner Park.

ATC also believes there are benefits associated with an interconnection to Xcel Energy and Dairyland Power Cooperative, though the study work to confirm these potential benefits is ongoing.

Zone 2

Stiles-Plains double circuit 138 kV line

This proposed project addresses the most limiting transmission element to transferring power from Wisconsin to the Upper Peninsula of Michigan. Due to the critical nature of this line, it cannot be taken out of service to be uprated (rebuilt) without severely jeopardizing the ability to serve load in the Upper Peninsula. Various energized rebuild and reconductor options were evaluated. Based upon these analyses, ATC believes the most prudent method of uprating this line is a complete rebuild. Replacement of the structures and the use of larger conductors will improve the reliability and improve the emergency transfer capability and voltage stability transfer limits. The in service year was changed from 2004 to 2005 due to numerous complications encountered with planning the rebuild of the line while maintaining the Wisconsin to Upper Peninsula transfer capability. To minimize the risks associated with keeping the line energized during construction, a temporary line on the same right-of-way is planned on the northern most 21 miles (Plains-Amberg). On the southern 44 miles (Amberg-Stiles), obstructions along much of the right-of-way prevent the use of a temporary line, so ATC is planning to rebuild the existing Amberg-West Marinette 69 kV line and convert it to 138 kV. The Amberg-West Marinette 138 kV line would essentially form a bypass around Amberg-Stiles, allowing ATC to rebuild the Amberg-Stiles line segment conventionally, negating the need for an alternative energized rebuild method.

Nordic-Randville Substation -rebuild single circuit 69 kV to double circuit 69 kV

The opportunity for ATC to accelerate this work from 2005 to 2004 surfaced due to internal resource scheduling.

Zone 3

Rockdale to Boxelder 138 kV line

The scope of work is included in the Jefferson-Lake Mills-Stony Brook 138 kV line project since it is not required until this new network line is constructed and placed in

service. The year of need is tied directly to the in service of the new line; therefore, this work is being deferred from 2005 to 2007.

Jefferson-Lake Mills-Stony Brook 138 kV line

The in service year for this project has been deferred from 2006 to 2007 due to the additional time required to perform pre-certification work on the new right-of-way that will be required for this project.

Construct a new 138 kV line from Rubicon substation to Hustisford substation and rebuild the Hustisford to Horicon 69 kV line to 138 kV (new)

In the course of planning for the transmission needs in Dodge County, several projects have been contemplated. In the 2003 10-Year Assessment, conversion of 69 kV facilities from Columbus through Beaver Dam to 138 kV was considered the best short-term solution with conversion of the South Fond du Lac-Springbrook 69 kV line to 138 kV as a future reinforcement. Shortly after the 2003 10-Year Assessment was issued, ATC proposed swapping the timing of these projects. In the course of evaluating these two alternatives, ATC found that even if both projects were constructed, the system would still experience voltage problems within the next 10 years, and additional reinforcements would be warranted. As a result, additional alternatives have been evaluated.

Recently, ATC has initiated discussions with affected customers to evaluate transmission needs and alternatives while considering distribution needs in the area. Based on the discussions to date, ATC believes that a new alternative, the Rubicon-Horicon 138 kV line, represents the best overall project. This project would address reliability issues for a longer period of time than the two previously considered alternatives.

The Rubicon-Horicon project also will involve the conversion of Hustisford substation to 138 kV along with the installation of a new substation near Horicon with a 138/69 kV transformer. This project is needed to resolve voltage problems in Juneau and Horicon areas, and to address loading and voltage problems on the transmission system near Beaver Dam and Mayville. Since additional time is required to pre-certify, license and build the new 138 kV line from Rubicon to Hustisford, the planned in service date for this project is 2008, rather than the 2007 in service date indicated for the Beaver Dam reinforcement in the 2003 10-Year Assessment.

Brooklyn-Belleville 69 kV line (now Brooklyn-Sugar River)

Sugar River substation (new)

Sugar River-Southeast Fitchburg 138 kV line

These projects were proposed to address low voltages anticipated in the area by 2007. The Brooklyn to Belleville (changed to Sugar River) 69 kV line in service date has been moved up from 2009 to 2007, while the new line from Southeast Fitchburg to Sugar River will be deferred from 2007 until 2009. This deferral is being done to allow enough time for pre-certification activities and CPCN approval for this new 138 kV line on new right-of-way. Providing voltage support to this area requires the new Brooklyn to Sugar

River line be installed by 2007. Long-term needs are expected to require the addition of a new 138 kV line from Southeast Fitchburg.

Zone 4

Werner West-Clintonville 138 kV line

This proposed project relieves congested 138 kV facilities in the Green Bay area, reduces system losses, improves operating flexibility and interconnects with new 345 kV facilities that will be needed if the proposed Weston Unit 4 Power Plant is approved and constructed. Constructing that line to accommodate a 138 kV circuit from Werner West to Clintonville was originally proposed in ATC's 2002 Assessment, but could not be justified based on the 2003 10-Year Assessment analysis. Upon more detailed subsequent analysis, ATC has determined that a 138 kV line from Clintonville to Werner West, which could be strung primarily on the Morgan-Werner West 345 kV line structures, would provide significant system benefits and could be strung at the same time the Morgan-Werner West 345 kV line is constructed. Those benefits include reduced loading on the Highway V-Preble-Tower Drive 138 kV line, the North Appleton-Lawn Rd-White Clay 138 kV line, the Badger 138/115 kV transformer, the Badger-Caroline 115 kV line and facilitating a future de-energized rebuild of the Pulliam-Stiles double circuit 138 kV line, which would not be possible under current system conditions. In addition, the Clintonville-Werner West line will provide a second 138 kV source to the city of Clintonville. Therefore, ATC is proposing that the project be changed to include a new 138 kV circuit from Clintonville to Werner West.

Erdman-Howards Grove 138 kV line

ATC originally proposed constructing a 5-mile 138 kV line, on new right-of-way, from the existing Erdman substation to a new substation named Howards Grove in response to an Alliant T-D request. Since the 2003 10-Year Assessment, Alliant has proposed a location change for the Howards Grove substation site. In addition, ATC has determined that unused right-of-way from the new Howards Grove site to ATC's Forest Junction-Cedarsauk 138 kV line (approximately 2.3 miles) could be used. ATC is now proposing to construct a 2.3-mile double circuit 138 kV line on this existing unused right-of-way, to loop the Forest Junction-Charter Steel 138 kV line into the proposed Howards Grove substation.

Replace 400 Amp Current Transformer at South Fond du Lac 69 kV

This project had been proposed to address a potential overload on the South Fond du Lac-Willow Lawn 69 kV line. The current transformer had been determined to be the limiting element on this line. As a result of more detailed analysis, the current transformer was found to have a rating factor that enabled it to be operated at an ampacity greater than 400 amps and therefore the project was canceled.

Lodestar-Sheboygan Falls 138 kV line

In its 2002 Assessment, ATC identified that 138/69 kV transformers in and around Sheboygan were reaching their ratings. In the 2003 10-Year Assessment, ATC evaluated several alternatives and found that a new 138 kV line from Lodestar to Sheboygan Falls would adequately address these transformer issues. Since that time, ATC has continued to

evaluate various options. Based on this analysis, ATC now concludes that replacing four transformers (two at Edgewater, one at South Sheboygan Falls and one at Mullet River) performs better from a system perspective, is likely to be more cost-effective, can be implemented in a more timely fashion, and requires no new right-of-way.

Zone 5

Hartford 138 kV capacitor bank

This new project is proposed as a result of low voltages that were identified in the Hartford area. A 26 MVAR capacitor bank is scheduled to be installed in 2005.

Rockdale-Lannon Junction 345 kV line

This project was proposed as a result of numerous low bus voltages that were identified in eastern Jefferson, western Waukesha and southern Washington counties, all areas where load growth has been and continues to be high. In addition to improving voltage profiles, reducing loadings on parallel 138 kV circuits and reducing losses, the proposed reinforcements will improve ATC's existing east-west transfer capability. The project was initially proposed as follows:

- ❑ Construct a new 345/138 kV Lannon Junction substation at the intersection of Forest Junction-Arcadian 345 kV line, Arcadian-Granville 345 kV line, and Germantown-Bark River 138 kV and Sussex-Tamarack 138 kV lines and install a 500 MVA, 345/138 kV transformer at this substation
- ❑ Construct a second Germantown-Lannon Junction 138 kV line
- ❑ Rebuild Rockdale-Jefferson-Concord 138 kV line to double circuit 345/138 kV and install a 500 MVA, 345/138 kV transformer at Concord
- ❑ Convert the Bark River-Lannon Junction 138 kV line to 345 kV operation and install a 500 MVA, 345/138 kV transformer at Bark River
- ❑ Construct a new 345 kV line from Concord to Bark River

A more detailed analysis concluded that the second Germantown-Lannon Junction 138 kV line was no longer needed. The initial reasoning for the second Germantown-Lannon Junction line was to ensure stable operation under contingency. However, the stability situation was no longer an issue after the second breaker was installed on the Germantown-Bark River line.

Additionally, it was found that looping a second 345 kV line into the new Lannon Junction substation provides minimal initial benefit to the transmission system at an additional cost of \$3.6 million. Although the substation will be designed to ultimately accommodate future expansion, it is not cost-effective at this time to loop the Forest Junction-Arcadian 345 kV line into the proposed Lannon Junction substation.

System reinforcements for Elm Road generation

We Power submitted an application to the Wisconsin PSC proposing installation of 1950 megawatts of generation facilities at the existing Elm Road generation site in three phases of 650 megawatts each to be in service by June of 2007, 2009 and 2011.

The transmission facilities associated with the Elm Road generation project listed in the 2003 10-Year Assessment were required based on the results of thermal and stability studies conducted on these proposed generation facilities including the impacts of two competing interconnection requests. One request included the proposed connection of 1,194 megawatts on the Arcadian – Zion 345 kV line and the other request included the proposed connection of 375 megawatts on the Arcadian – Pleasant Prairie 345 kV line. Both of these requests have since been withdrawn. The PSCW order issued on the Elm Road generation application approved only two of the three phases with in-service dates of June 2009 and 2010. Following the issuance of the 2003 10-Year Assessment, stability restudies were conducted for the approved Elm Road generation facilities and with the withdrawal of the two interconnection requests. As a result of those studies, the in-service dates and required transmission facilities associated with the Elm Road generation project have been revised in this 2003 Update to reflect the latest findings. The affected projects are listed below:

- ❑ *Reconductor segment of the Oak Creek-Ramsey 138 kV line*
- ❑ *Reconductor underground segment of Ramsey-Harbor 138 kV line*
- ❑ *Reconductor Oak Creek-Allerton 138 kV line*

The in-service year for above three projects has been deferred from 2007 to 2009 because of the change in the in-service date of the first unit at Elm Road.

- ❑ *Construct an Oak Creek-Brookdale 345 kV line*
- ❑ *Construct a Brookdale-Granville 345 kV line*
- ❑ *Construct Oak Creek-St Martins 138 kV circuit*
- ❑ *Restring Bluemound-Butler 138 kV line on new 345 kV structures installed with Brookdale-Granville line*
- ❑ *Construct Butler-Tamarack (Carmen) 138 kV line on new 345 kV structures installed with Brookdale-Granville line*
- ❑ *Construct a 345/138 kV switchyard at Brookdale to accommodate two 345 kV lines, a 345/138 kV transformer and four 138 kV lines plus two 138/26.2 kV transformers*

The in-service year for the above six projects has been deferred from 2007 to 2010. This change is due in part to the change in the in-service date of the Elm Road generation, and in part to the results of the restudy conducted for Phases I and II, which shows the line is not required with the first 650-megawatt unit but is required with the installation of the second 650-megawatt unit (Phase II). The restudy also reflects a new connection configuration for the Elm Road generators.

- ❑ *Convert and reconductor Oak Creek-Bluemound 230 kV line to 345 kV*

This project is deleted from the list of 2007 projects and canceled because the restudy results show that the conversion of the line is not required for system stability purposes in Phases I, II or III of the proposed generation project at Elm Road without the competing generation in area.

- *Construct 345 kV Bluemound switchyard to accommodate one 345 kV line and a 345/138 kV transformer*

The in-service year for the above project has been deferred from 2007 to at least 2012. The restudy results of Phases I, II and III show that the construction of this substation is not required for system stability purposes unless Phase III of the Elm Road generation project is developed.

- *Expand Oak Creek 345 kV switchyard to interconnect one new generator*

The in-service year has been deferred from 2007 to 2009 because of the change in the in-service date of the first Elm Road unit from 2007 to 2009. In addition, a more detailed analysis in the restudy for Phase I of the Elm Road generation project suggests a revision to the switchyard project. It has been determined that both the existing Oak Creek 345 kV and 138 kV switchyards and associated facilities are to be replaced with a new switchyards in new locations. The only required expansion to the Oak Creek 345 kV switchyard in Phase I of the project is the interconnection of the one new generator. The expansion of the 138 kV switchyard to accommodate a new St. Martins line is deferred from 2007 to 2010 because the restudy results for Elm Road Phases I and II show the line is not required until Phase II of the Elm Road generation project and that the in-service date for the second unit has moved from 2009 to 2010.

- *Reconnect Oak Creek Unit 7 to 345 kV switchyard*

This project is deleted from the list of 2007 projects because the restudy results show that this system modification is not required for system stability purposes in Phases I, II or III of the Elm Road generation project.

- *Install two 345 kV series breakers at Pleasant Prairie on lines to Racine (L631) and Zion (L2221)*

The in service year for this project has been deferred from 2007 to 2009 because of the change in the in-service date of the first unit at Elm Road. Upon more detailed analysis in the restudy for Phase I of the Elm Road generation project, it has been determined that the most prudent method to provide delayed clearing times to meet stability criteria is to replace the existing circuit breakers with independent pole operation breakers that include redundant high-speed relaying, signal connection and DC battery supply. If there is insufficient space for an IPO breaker at either Pleasant Prairie position, then an alternative proposal is to install another line breaker in series with the existing line breaker at each position.

- *Replace seven 138 kV overdutied breakers at Bluemound*

The in-service year for this project has been deferred from 2007 to 2009 because of the change in the in-service date of the first unit at Elm Road. The short circuit restudy for Phase I of the Elm Road generation project is currently under way but has not yet been completed. The results of this restudy could possibly reduce the number of breakers needing replacement.

- ❑ *Uprate Kansas-Ramsey 138 kV line*
- ❑ *Uprate Oak Creek-Ramsey 138 kV line*

The in-service year for the above two projects has been deferred from 2008 to 2009 because of the change in the in-service date of the second Elm Road unit.

- ❑ *Install second 345/138 kV transformer at Oak Creek*

The in-service year for this project has been deferred from 2008 to 2009 because of the change in the in-service date of the second Elm Road unit.

- ❑ *Expand 345 kV switchyard at Oak Creek to interconnect one new generator, plus one new 345 kV line and 138 kV switchyard to accommodate new St. Martins line*

The in service year for this project has been deferred from 2009 to 2010 because of the change in the in-service date of the second Elm Road unit. The expansion of this project is due to the result of the restudy conducted for Elm Road Phases I and II and the deferral of a 345 kV and 138 kV line from Phase I to Phase II.

- ❑ *Expand Oak Creek 138 kV switchyard to reconnect Units 6 and 9*

The in-service year for this project has been deferred from 2011 to at least 2012 because of the uncertainty in the in-service date of a possible third Elm Road unit. Upon more detailed analysis in the restudy for Phase III of the Elm Road generation, this project is being revised as follows: Oak Creek Unit 6 would still be reconnected to the 138 kV switchyard as originally planned for Phase III. However, it has been determined from the results of the restudy that Oak Creek Unit 9 would remain connected at the Oak Creek 230 kV substation as it is today and would not be reconnected to the 138 kV bus in Phase III of Elm Road.

- ❑ *Expand 345 kV switchyard at Bluemound to accommodate three additional 345 kV lines and two additional 500 MVA 345/138 kV transformers*
- ❑ *Reconnect Oak Creek Unit 8 to 345 kV switchyard*
- ❑ *Reroute Brookdale-Granville 345 kV line into expanded Bluemound 345 kV switchyard*

These three projects are deleted from the list of 2011 projects and canceled because the restudy results show that this system modification is not required for system stability purposes for Phase III of the Elm Road generation.

- ❑ *Convert and reconductor Oak Creek-Bluemound 230 kV line to 345 kV and loop into Arcadian 345 kV substation*
- ❑ *Construct Oak Creek-Racine 345 kV line*

The in-service year for the above two projects has been deferred from 2011 to at least 2012 because of the uncertainty in the in-service date of a possible third Elm Road unit. The restudy results for three Elm Road units confirm that these projects are still required for system stability purposes.

- *Replace 22 overdutied 138 kV breakers at Harbor, Everett and Haymarket substations*

The in-service year for this project has been deferred from 2011 to 2012 because of the uncertainty in the in service date of a possible third Elm Road unit. The short circuit re-study for three Elm Road units has not yet been started. The results of this restudy could possibly reduce the number of breakers needing replacement.

- *Expand Oak Creek 345 kV switchyard to interconnect three new generators*

The in-service year for the above project has been deferred from 2011 to at least 2012 because of the uncertainty in the in-service date of a possible third Elm Road unit. Upon more detailed analysis in the restudy of three Elm Road units, this project is being revised. Expansion of the Oak Creek 345 kV switchyard to accommodate the three new units and the two 345 kV lines will still be required as originally planned. However, it has been determined from the results of the restudy that the installation of the eight 345 kV series breakers and the connection of Oak Creek Unit 8 will not be required with three Elm Road units and therefore can be eliminated from the project.

Umbrella Plans

As described in the 2003 10-Year Assessment, ATC has performed analyses that created a Northern Zones Umbrella Plan (Zones 1, 2 and 4) and a Southern Zones Umbrella Plan (Zones 3 and 5). These plans were developed to most efficiently and effectively address the combined issues and need drivers identified within the northern and southern portions of ATC's system. These umbrella-planning activities serve two primary purposes:

1. To evaluate the needs and address issues within the northern and southern portions of the ATC system and develop preliminary plans that adequately address those needs and issues, and
2. To evaluate and refine the preliminary plans based on analyses of various future scenarios.

Since the 2003 10-Year Assessment, ATC has conducted analyses and made numerous refinements to the first phase of its Northern Umbrella Plan. The first phase of the Northern Umbrella Plan is described below. No additional analyses have been conducted of its Southern Umbrella Plan since the 2003 10-Year Assessment, though several reinforcements that were part of that plan have been evaluated and refined.

During 2004, ATC intends to undertake extensive analyses focused on improving our customers' access to energy markets. These analyses will necessarily dovetail with the second phase of development and refinement of the Northern and Southern Umbrella Plans.

Northern Umbrella Plan (Phase 1)

Analyses of the first phase of the Northern Umbrella Plan have been done over the past year to define and refine the projects that comprise the plan. A key component in these activities has been the involvement of affected customers. ATC has met several times with these customers to discuss issues to be resolved, the findings of analyses of project alternatives and to obtain consensus.

The primary considerations in developing the first phase of the northern plan are (1) the chronic limitations to transferring power between Wisconsin and the Upper Peninsula of Michigan and (2) the vulnerability of the system to widespread outages. The northern plan was developed to address these two and other issues. The discussion below describes the pertinent issues, the components and the effects of the Northern Umbrella Plan. The plan is shown graphically in Figure IV-1.

Background

The most chronic problem plaguing day-to-day operation of ATC's transmission system is the limited transfer capability between Wisconsin and the Upper Peninsula of Michigan. Transfer capability becomes limited whenever an element in the transmission system reaches its thermal rating or when the voltage stability limit for transfers to the Upper Peninsula is reached. The resulting effects include:

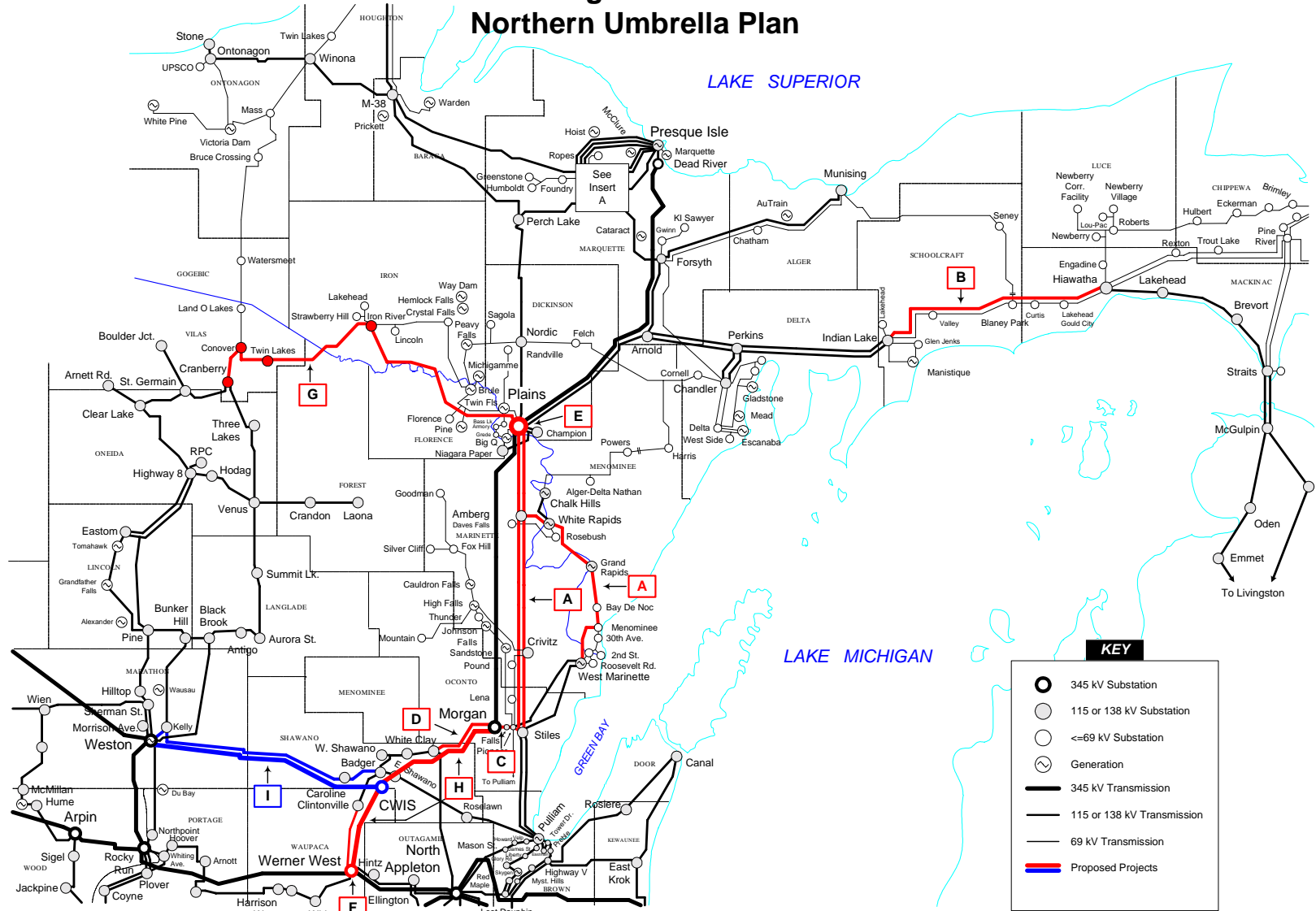
- ❑ Uneconomic dispatch of generation, costing ATC customers millions of dollars annually (over \$10 million from 2001 through 2003), which is expected to continue until limitations are resolved.
- ❑ Chronic interruption or curtailment of transmission service due to the need to invoke Transmission Loading Relief measures. These TLR events have increased from 80 days in 2001 to 230 days in 2003.
- ❑ Frequent reconfiguration of the system (opening the Hiawatha-Indian Lake 69 kV lines), resulting in reduced reliability of the system in Schoolcraft, Luce, Chippewa and Mackinac Counties.
- ❑ Operating near system security limits for extended periods of time, an undesirable operating situation. This situation is an indication that there is little cushion in the system to ride through forced and scheduled outages.
- ❑ Limited ability to schedule maintenance without invoking redispatch, system reconfiguration or other measures—all of which either add to system operation cost or reduced reliability, or both.

The nature of these system limitations changes seasonally. They surface on transmission facilities located in ATC Planning Zone 4 south of Green Bay to facilities located in ATC Planning Zone 2 covering the eastern Upper Peninsula. Given the dynamic nature of these limitations, resolving them will require that several system reinforcements be implemented in a closely coordinated fashion over the next several years.

The system limitations that surface at any given time depend on the following set of variables:

- ❑ system load,
- ❑ what generation is operating,
- ❑ which transmission facilities are out of service,
- ❑ how much power is being scheduled to the Upper Peninsula from Wisconsin, and
- ❑ network loop flows, which can add additional stress to the subject transmission facilities.

Figure IV-1 Northern Umbrella Plan



At various points in time, 21 separate system elements have limited transfer capability between Wisconsin and the Upper Peninsula. Fifteen different 138 kV lines, a 115 kV line, a 69 kV line, two different 345/138 kV transformers and two different 138 kV substations comprise those elements and are located from the Wisconsin/Michigan border to south of Appleton. Several of the facilities that show up as limitations also are well beyond their design life with the following three having more than 70 years in service:

- ❑ Plains-Amberg-Stiles 138 kV double circuit line (1925)
- ❑ Bay de Noc-Grand Rapids 69 kV (line conductor is 1922 vintage—poles were rebuilt in 1931—which is part of West Marinette-Amberg route)
- ❑ Twin Falls-Iron River 69 kV (built in 1912 with sections replaced in 1921)

ATC's goals in addressing these related issues are:

- ❑ to increase transfer capability between Wisconsin and the Upper Peninsula,
- ❑ minimize the impact on system operation while system reinforcements are being implemented,
- ❑ address facility condition issues to the extent practical,
- ❑ achieve greater reliability to reduce the risk of widespread outages in the Upper Peninsula, and
- ❑ achieve all of these benefits at the lowest reasonable cost.

As part of its Northern Umbrella Plan analyses, ATC evaluated 19 project alternatives in roughly 140 combinations to determine which alternatives performed best at meeting the above goals. In general, the combinations of alternatives involving certain projects tended to perform better from a network perspective. Those projects exhibiting superior performance were further evaluated in terms of capital cost, constructability, existing facility condition issues, potential environmental impacts, impacts on customers, and response to extreme conditions (varying load and generation in the Upper Peninsula). Based on the evaluations conducted, ATC has developed the following list of reinforcement projects, for which it plans to seek appropriate regulatory approvals. *Italicized projects below have changed in scope from what was reported in ATC's 2003 10-Year Assessment.*

- ❑ Rebuild Morgan-Stiles 138 kV line (in-service projection: 2005)
- ❑ Reconductor Morgan-White Clay 138 kV line (2006)
- ❑ *Rebuild Plains-Stiles 138 kV line*
 - ❑ *Rebuild Plains-Amberg double circuit line while energized, which will require construction of a temporary bypass line during construction (2005)*
 - ❑ *Convert and rebuild 69 kV facilities from White Rapids substation to West Marinette substation and rebuild 138 kV facilities from White Rapids to Amberg (2005)*
 - ❑ *Rebuild Amberg-Stiles double-circuit line, which can be de-energized following completion of the Plains-Amberg and Amberg-West Marinette projects (2006)*
- ❑ Rebuild Hiawatha-Indian Lake 69 kV line for double-circuit 138 kV operation (2005)

- String one circuit and operate at 69 kV until 2009
- String second circuit in 2009
- Convert both circuits to 138 kV operation in 2009
- Construct new Werner West 345/138 kV substation (2006)
- Install second 345/138 kV transformer at Plains substation (2007)
- Construct new Cranberry-Conover 138 kV line (2008)
- Install 138/115 kV transformer at Cranberry substation (2008)
- Rebuild portions of the Plains-Conover 69 kV facilities for 138 kV operation (2008)
- Construct new Werner West-Morgan 345 kV line (2009)
 - This project could involve rebuilding portions or all of the Clintonville-Badger-White Clay-Morgan 138 kV line
 - String a new 138 kV line on the new structures from Clintonville substation to Werner West substation

In addition to the projects described above, ATC is considering other system reinforcements that would address emerging reliability issues to the Upper Peninsula. In particular, rebuilding the 69 kV line from White Rapids to Chandler and converting that line to 138 kV operation is being considered. A portion of the line would be rebuilt for double circuit 138 kV and 69 kV operation. This project would complete a fifth high voltage tie between Wisconsin and the Upper Peninsula, improving system reliability and transfer capability, address an emerging condition issue on the subject line and improve reliability locally. More information on this potential project will be included in the 2004 Assessment.

Transfer Capability Limitations

The transfer capability limitations from Wisconsin to the Upper Peninsula result in significant generation redispatch costs. These limitations vary depending on a variety of factors, but generally can be quantified as follows:

- Summer season: 220 megawatts, due to the thermal capability of the Plains-Stiles line
- Winter season: 250 megawatts, due to voltage stability at and north of Plains

If only the Plains-Stiles line thermal rating was increased, numerous other 138 kV lines, near their ratings under various conditions, would limit transfer capability to less than the existing voltage stability limit. The key to addressing this situation is to develop a plan that is timely, minimizes system impacts during the construction of reinforcements, provides flexibility in the operation of the system, and resolves the limitations for the foreseeable future.

The results of studies done by ATC indicate that by implementing the Northern Umbrella Plan projects, the Wisconsin to Upper Peninsula transfer capability could be at least doubled, with the voltage stability limitation nearly tripling. These increases will:

- allow ATC to accommodate a firm transmission request beginning in 2008 (135 megawatts, WPS to UPPCo),

- ❑ provide considerably more emergency operation and maintenance scheduling flexibility, and
- ❑ reduce the risk of widespread outages in the Upper Peninsula.

In the course of implementing the Northern Umbrella Plan projects, modest increases in transfer capability are expected until the Morgan-Werner West 345 kV project is in service. Figures IV-1-1 through IV-1-10 show existing limitations that are expected to surface during the implementation of the northern plan projects, along with limitations that are resolved as each project is implemented. In these figures, the red ‘stop signs’ show thermal limitations that exist up to the transfer limit dictated by voltage stability under contingency conditions (loss of the Morgan-Plains 345 kV line), which is shown in the red oval near the top of each figure. The larger stop signs indicate thermal limits well below the voltage stability limit. The smaller stop signs indicate thermal limits closer to the voltage stability limit.

As projects are implemented and limitations are relieved, the stop signs are shown in green. It is important to note that limitations below the voltage stability limit surface during the implementation of the Northern Umbrella Plan projects. This is in part due to the fact that the voltage stability limit is increasing by varying amounts with the completion of each project. In particular, completion of the Cranberry-Conover line and Conover-Plains rebuild/conversion increases the number of limitations closer to the voltage stability limit, but the voltage stability limit is expected to increase by over 80 megawatts with that project.

Figures IV-1-1 through IV-1-10 indicate the limitations and limitations relieved for the following sequence of Northern Umbrella Plan project implementation:

<i>Figure</i>	<i>Powerflow Case Utilized</i>	<i>Projects Included</i>
IV-1-1	2005 shoulder peak	❑ None (existing system)
IV-1-2	2005 shoulder peak	❑ Plains-Amberg 138 kV line rebuild and Amberg-West Marinette 69 kV line rebuild/conversion to 138 kV (Project A, Phase 1)
IV-1-3	2005 shoulder peak	❑ Project A, Phase 1 ❑ Hiawatha-Indian Lake 69 kV line rebuild (Project B)
IV-1-4	2006 shoulder peak	❑ Project A Phase 1 ❑ Project B ❑ Morgan-Stiles 138 kV line rebuild and Morgan-White Clay 138 kV line reconductor (Projects C and D)

<i>Figure</i>	<i>Powerflow Case Utilized</i>	<i>Projects Included</i>
IV-1-5	2006 shoulder peak	<ul style="list-style-type: none"> ❑ Project A (Phase 1) ❑ Projects B through D ❑ Amberg-Stiles 138 kV line out of service to rebuild (Project A, Phase 2 during construction outage)
IV-1-6	2006 shoulder peak (note voltage stability limit is now lower on 138/115 kV system west of Green Bay than in the UP)	<ul style="list-style-type: none"> ❑ Project A (Phase 1) ❑ Projects B through D ❑ Amberg-Stiles 138 kV line out of service to rebuild (Project A, Phase 2 in service)
IV-1-7	2007 shoulder peak	<ul style="list-style-type: none"> ❑ Project A (Phase 1 and 2) ❑ Projects B through D ❑ Plains 345/138 kV transformer and Werner West 345/138 kV substation (Projects E and F)
IV-1-8	2007 shoulder peak	<ul style="list-style-type: none"> ❑ Project A (Phase 1 and 2) ❑ Projects B through F ❑ Cranberry-Conover 138 kV line and Conover-Plains 69 kV line rebuild/conversion to 138 kV (Project G)
IV-1-9	2008 shoulder peak	<ul style="list-style-type: none"> ❑ Project A (Phase 1 and 2) ❑ Projects B through G ❑ Arrowhead-Weston 345 kV line (shown in blue)
IV-1-10	2009 shoulder peak	<ul style="list-style-type: none"> ❑ Project A (Phase 1 and 2) ❑ Projects B through G ❑ Morgan-Werner West 35 kV line and Clintonville-Werner-West 138 kV line (Project H) ❑ Arrowhead-Weston 345 kV line (shown in blue)

Figure IV-1-1: 2005 Existing System

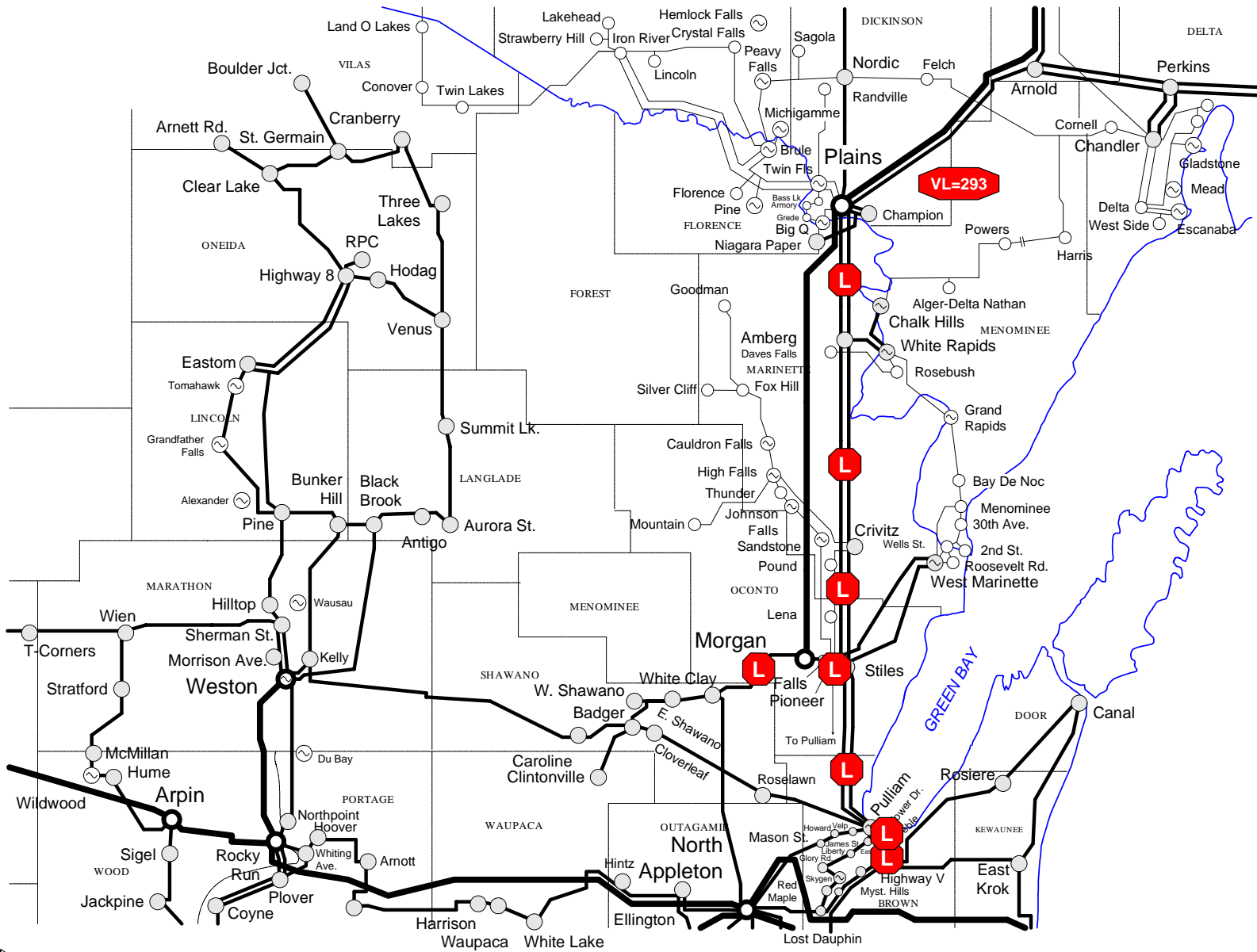


Figure IV-1-2: 2005 System
Add Project A - Phase 1: Plains-Amberg-W.Marinette 138 kV Rebuild

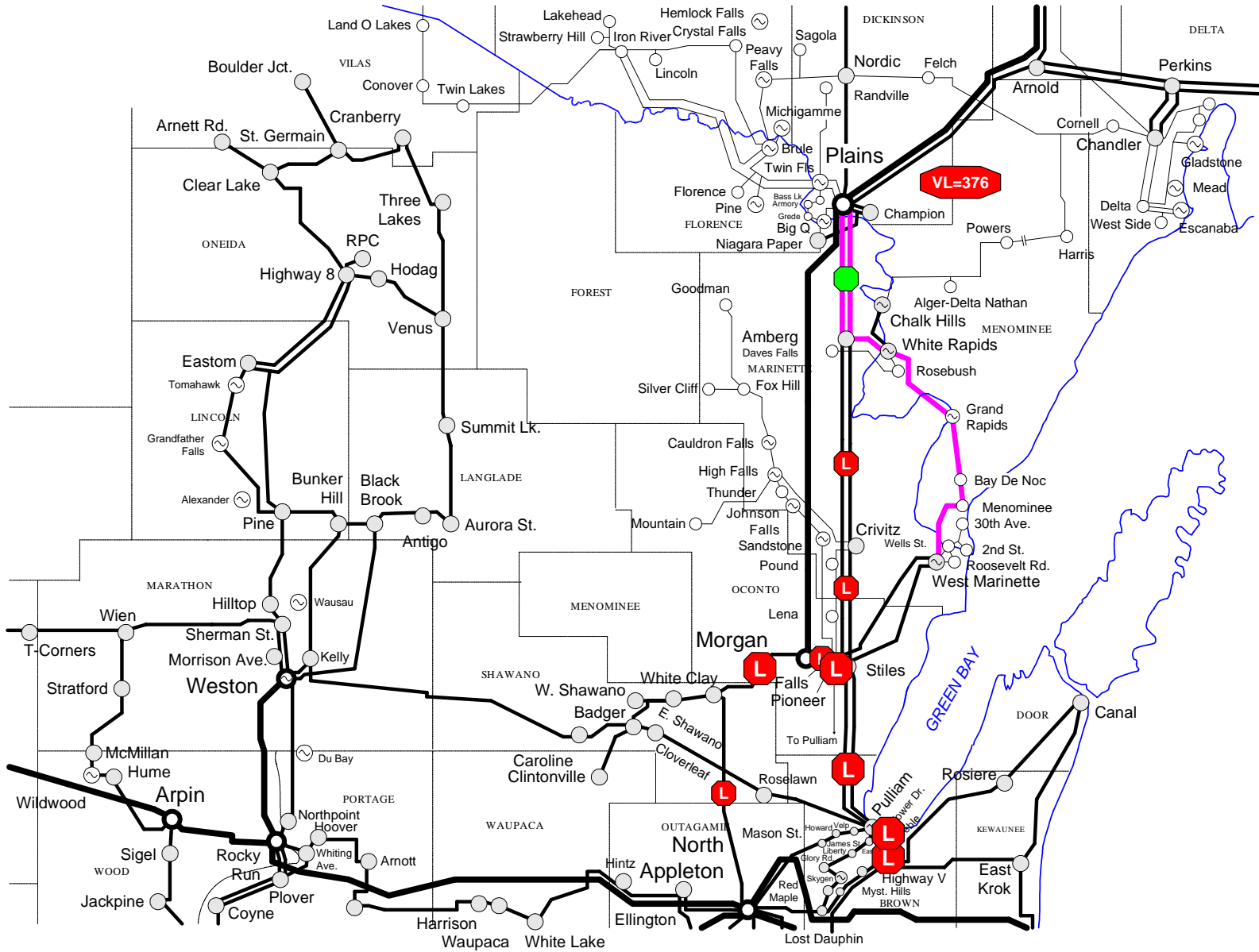


Figure IV-1-3: 2005 System With Project A - Phase 1
 Add Project B: Indian Lake-Hiawatha 69 kV

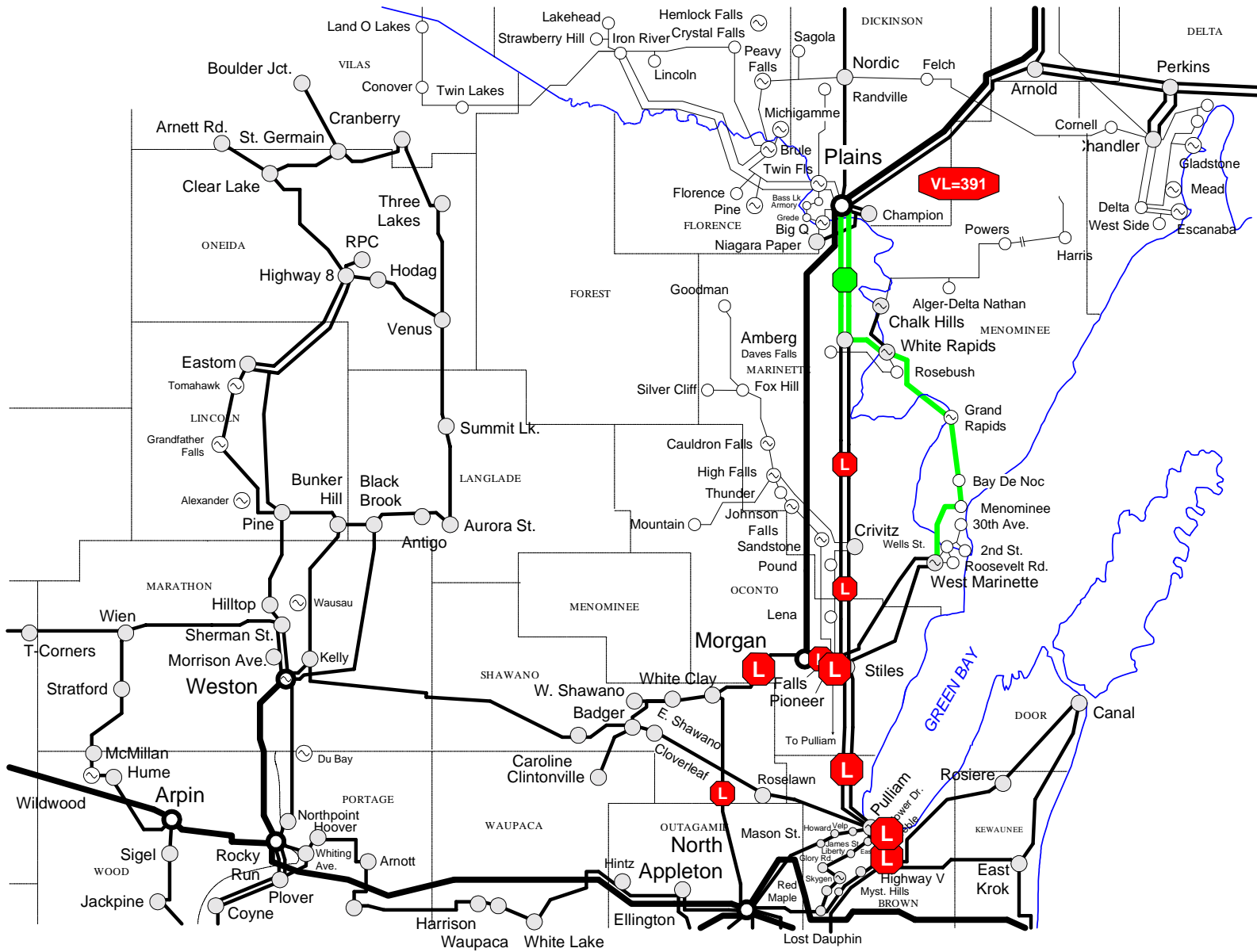


Figure IV-1-4: 2006 System With Projects A - Phase 1, B
Add Projects C + D: Morgan-Stiles 138 kV Rebuild + Morgan-White Clay 138 kV Reconductor

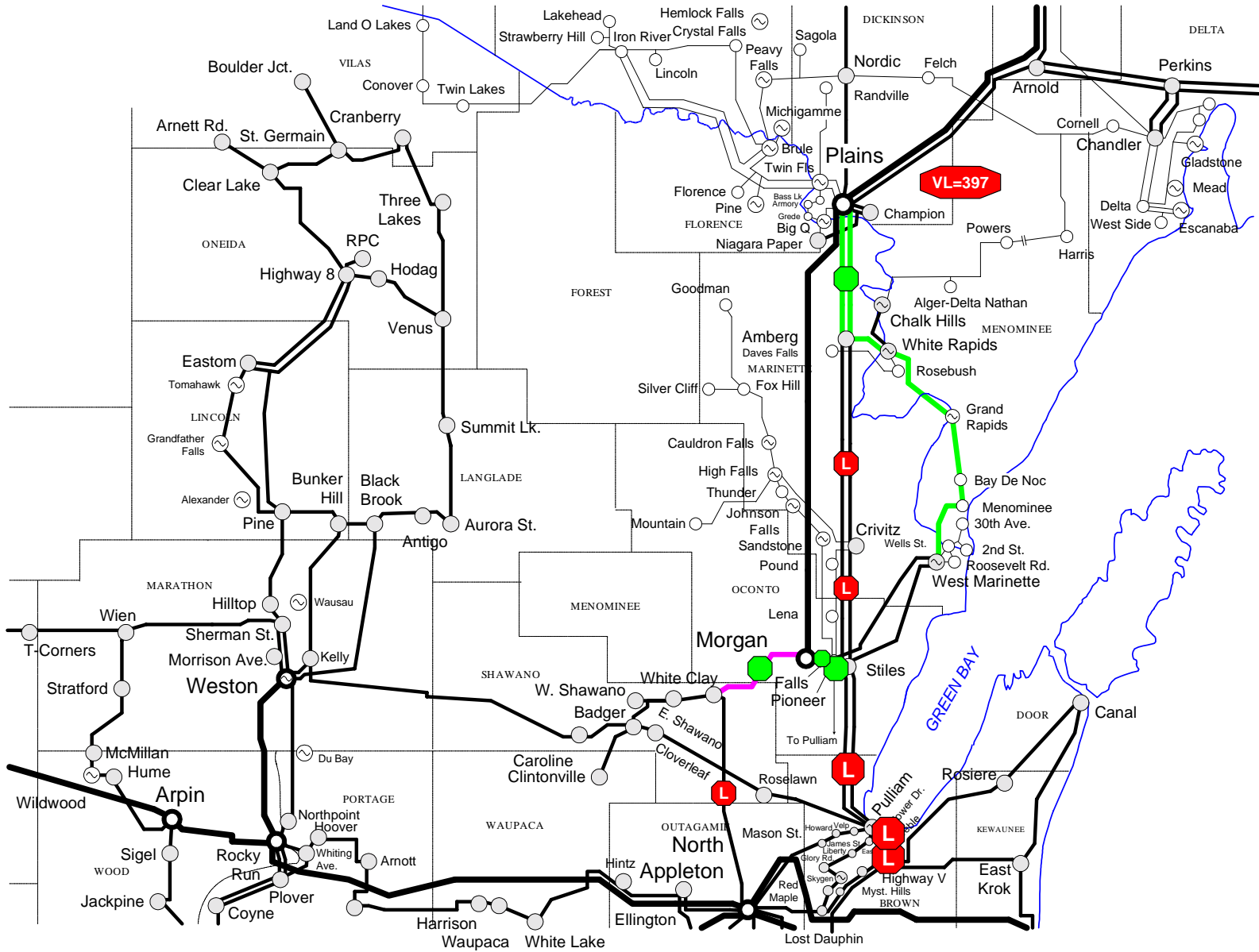


Figure IV-1-5: 2006 System With Projects A - Phase 1, B, C, D
 Amberg-Crivitz-Stiles 138 kV Out-Of-Service During Construction (Project A - Phase 2)

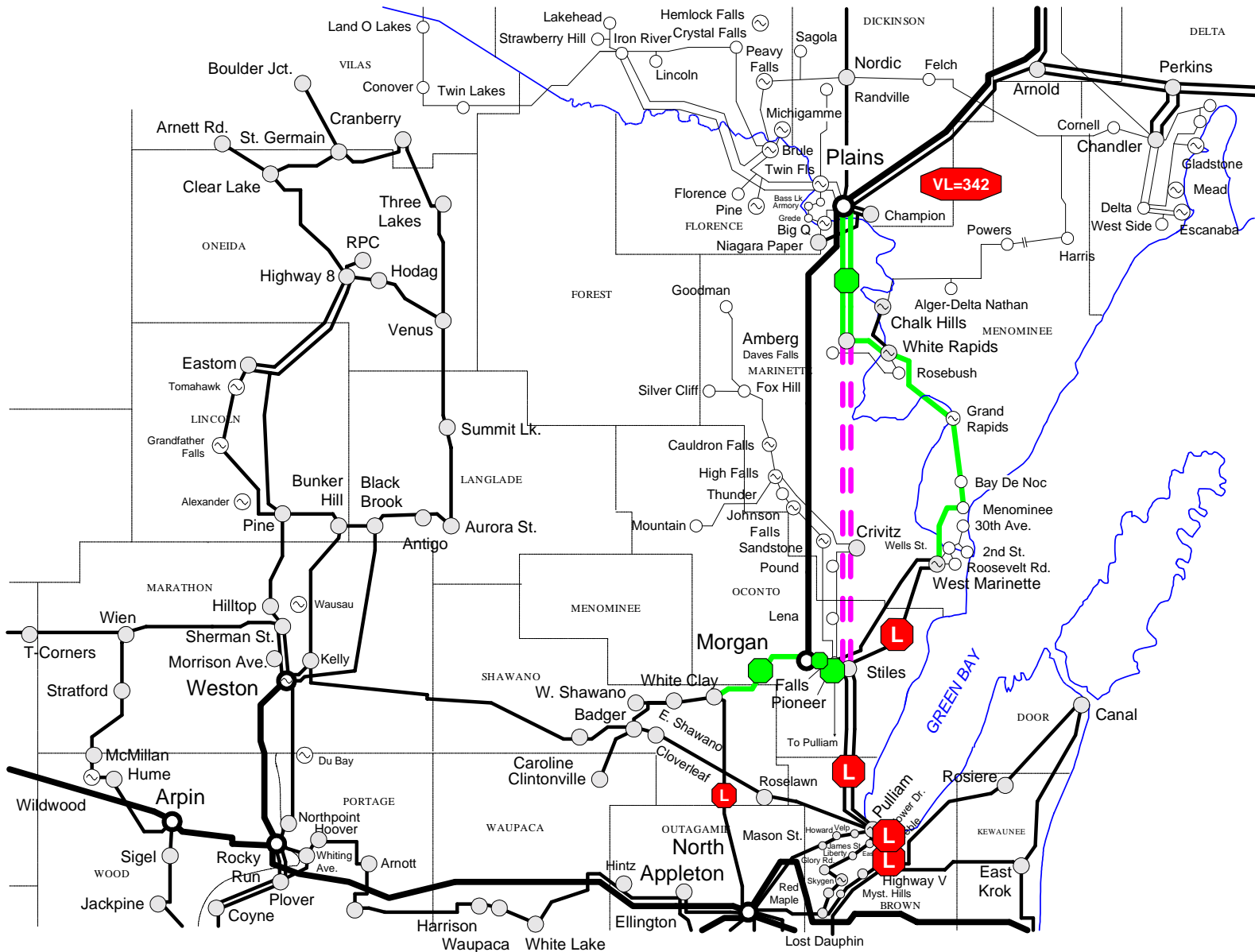


Figure IV-1-6: 2006 System With Projects A - Phase 1, B, C, D
Project A - Phase 2 Completed: Amberg-Crivitz-Stiles 138 kV Rebuild

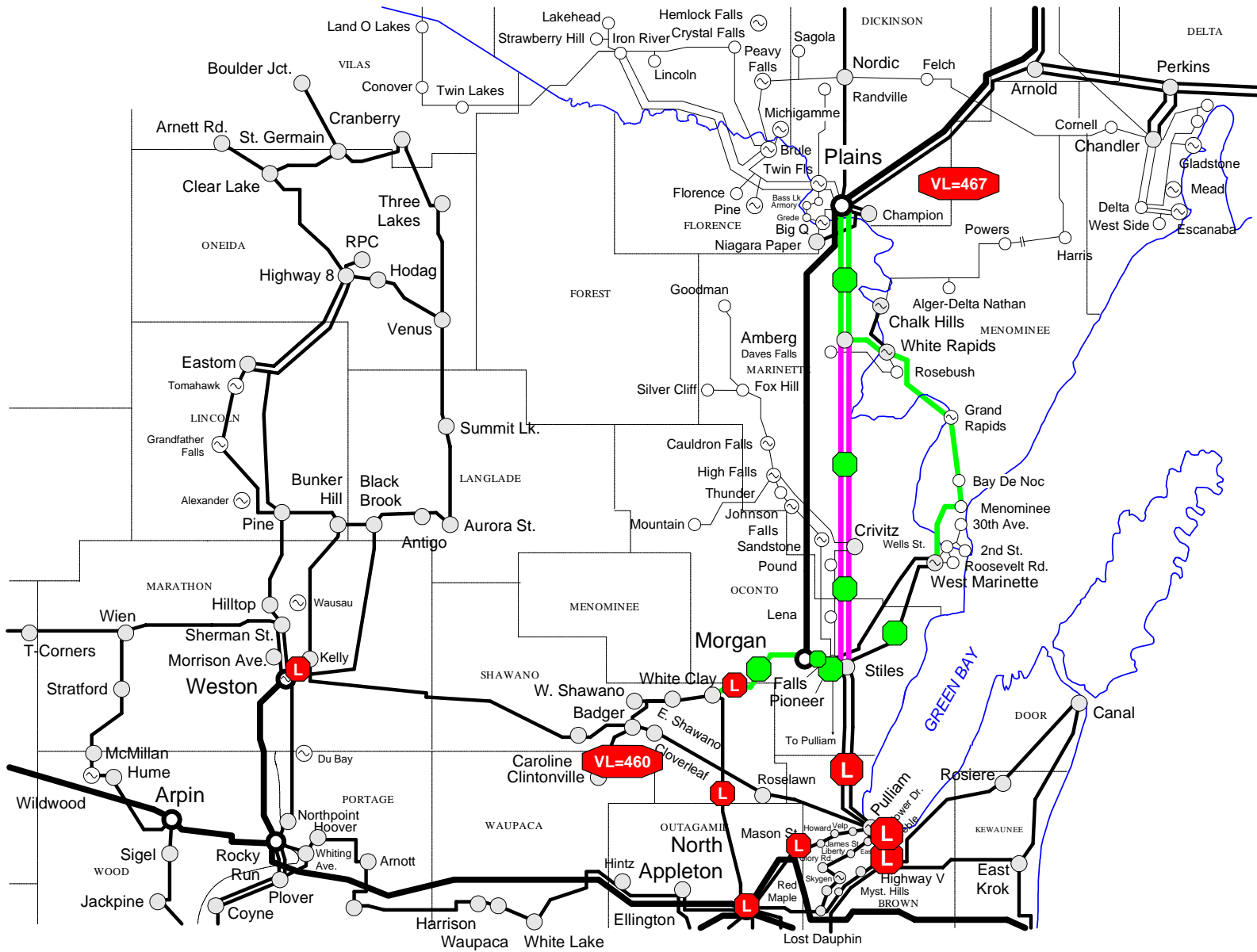


Figure IV-1-7: 2007 System With Projects A, B, C, D
 Add Projects E + F: Werner West & Plains 345/138 kV Transformations

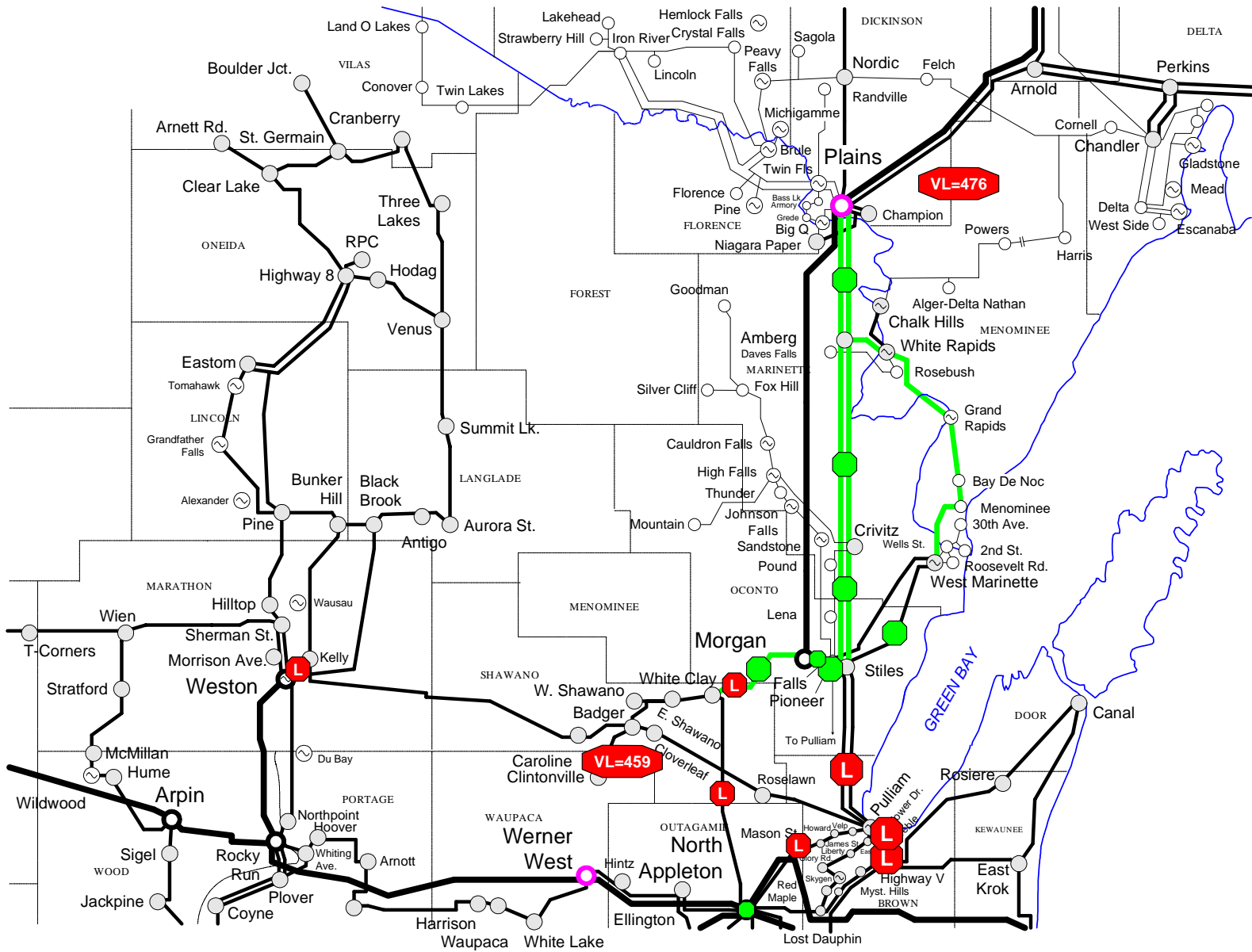


Figure IV-1-8: 2007 System With Projects A, B, C, D, E, F
Add Project G: Plains-Iron River-Conover-Cranberry 138 kV

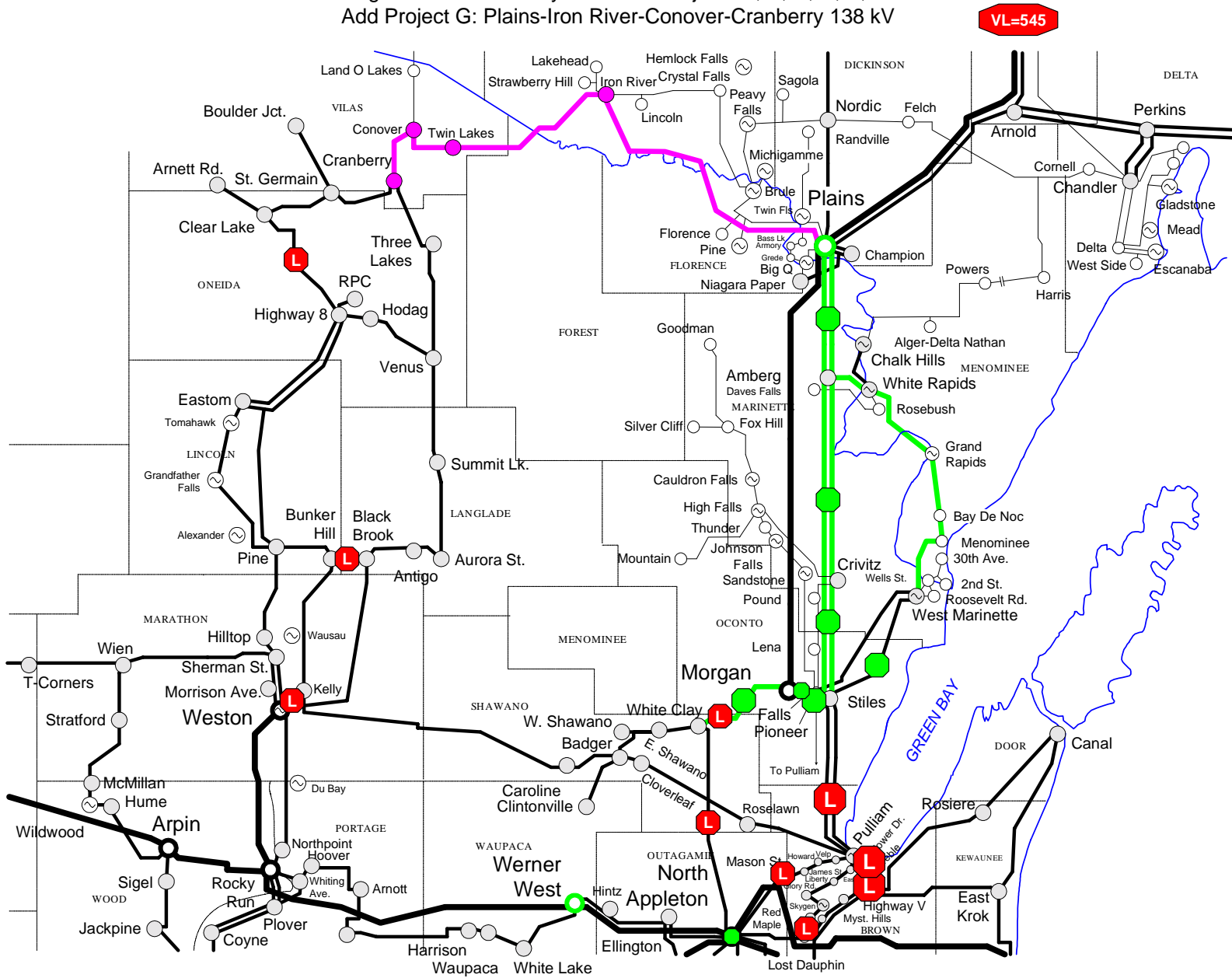


Figure IV-1-9: 2008 System With Projects A, B, C, D, E, F, G
 Add Arrowhead-Weston 345 kV

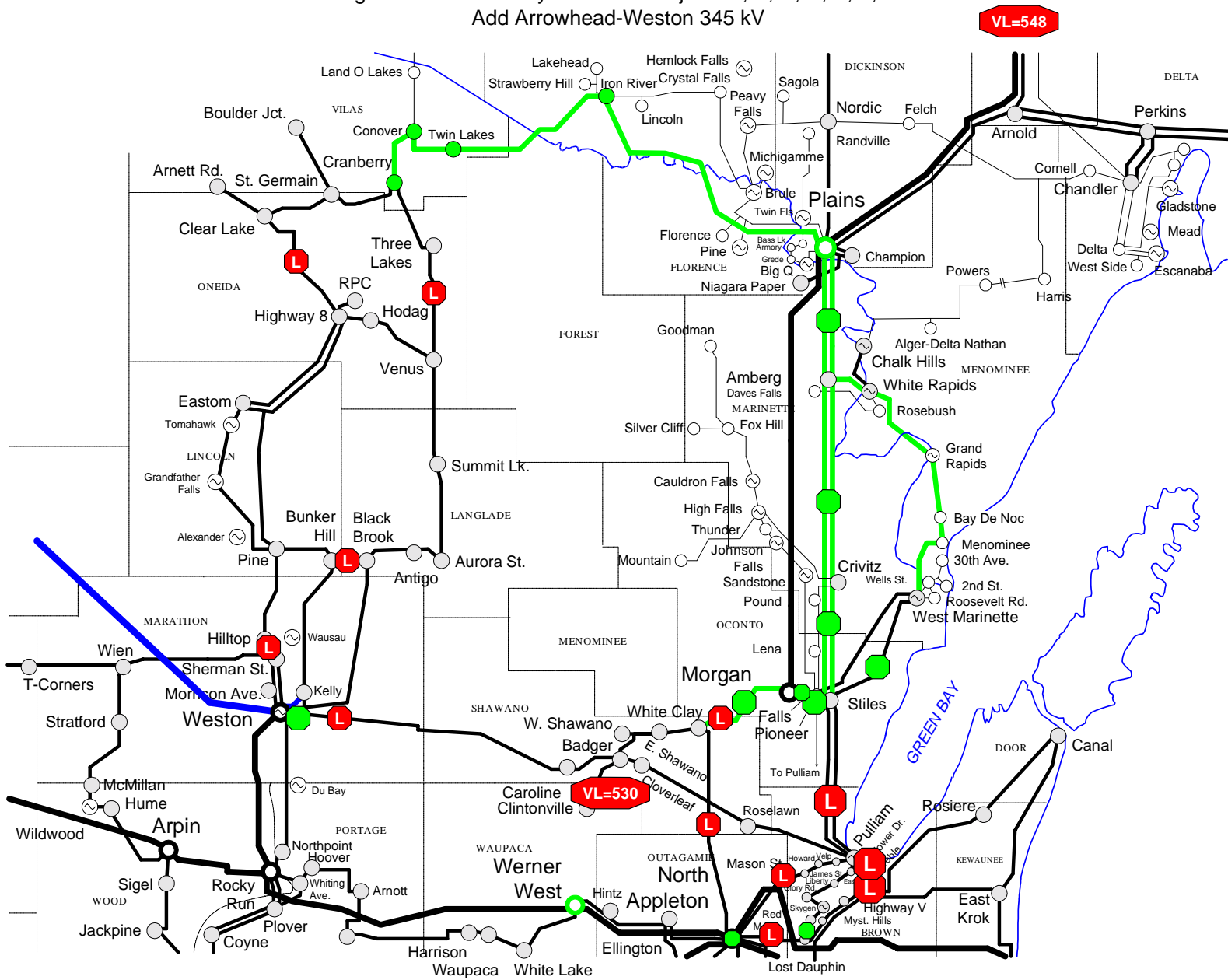
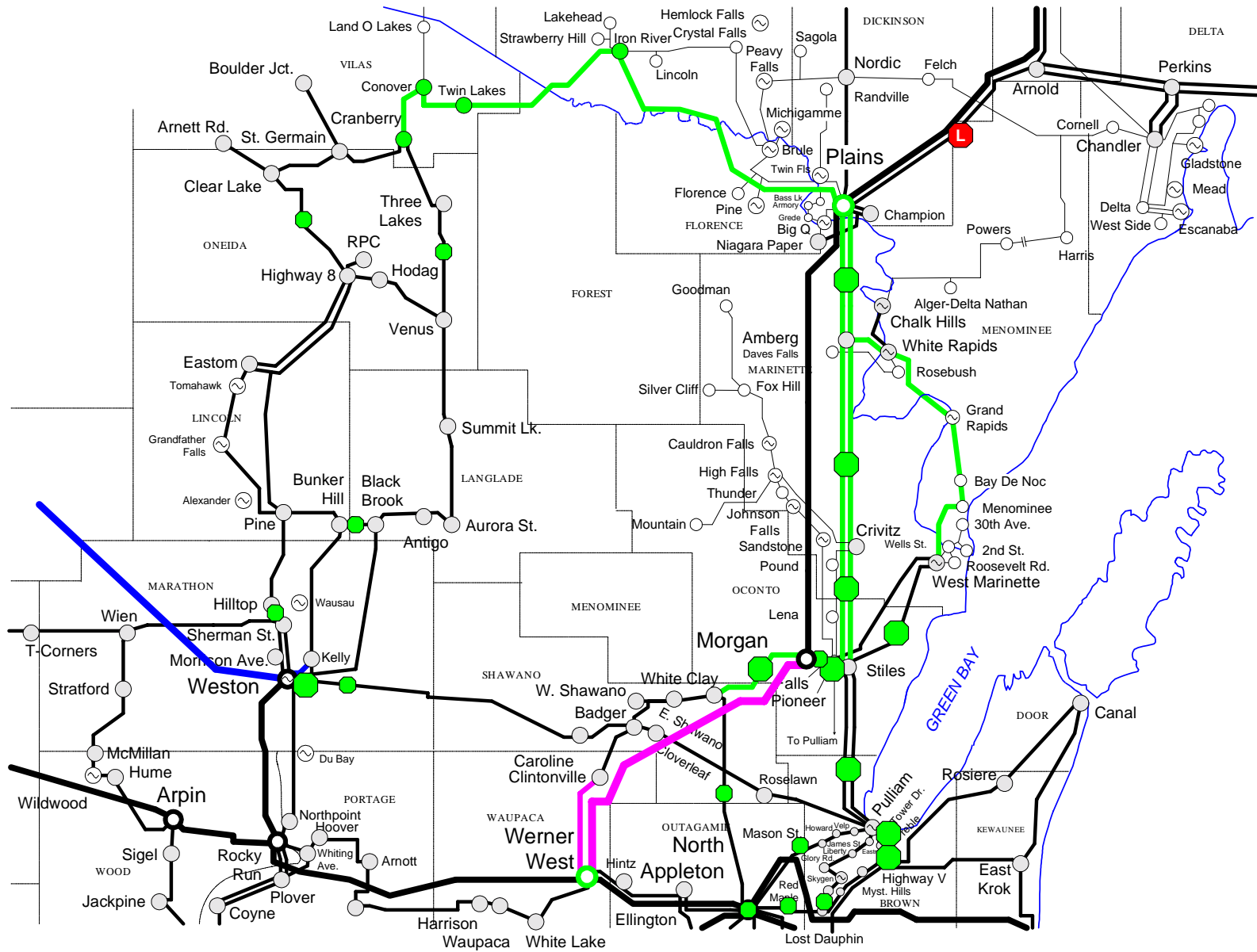


Figure IV-1-10: 2009 System With Projects A, B, C, D, E, F, G + Arrowhead-Weston 345 kV
Add Project H: Morgan-Werner West 345 kV + Clintonville-Werner West 138 kV

VL=583



Section V

SUMMARY OF FACILITY ADDITIONS IN THE 2003 10-YEAR ASSESSMENT UPDATE

Summary of Transmission System Additions: 2004-2012

The change in transmission facilities proposed by ATC based on this 2003 Update are listed in Table V-1 and shown graphically in Figures V-1 through V-5. Alternatives for some of the primary alternatives shown in Table V-1 are listed in Table V-2. Also, projects listed in the 2003 10-Year Assessment that are not included in this Update are listed in Appendix B.

In each of these tables, there is a column indicating the planned in-service year for each particular facility and a column indicating the year the facility is needed. There are numerous facilities for which the year it is needed precedes the planned in-service year. There are a variety of reasons for this, including:

- ❑ The preferred alternative to address a particular need may take several years to implement.
- ❑ The need may have previously existed but had been addressed with operating procedures that are becoming less effective or ineffective.
- ❑ The preferred alternative to address a particular need may need to be implemented in phases.
- ❑ New data or information became available that affected the nature of the need or limitation, which necessitated a change in the alternative to be implemented, introducing a delay in implementation.
- ❑ The need for a project was based on load or generation development that was uncertain.
- ❑ Stakeholder input necessitated a change in the alternative to be implemented, introducing a delay in implementation.

Within the tables, the need for each project is identified. Need categories include the following:

Reliability:

- ❑ Facility (line, transformer, substation equipment) normal rating is exceeded under normal system conditions.
- ❑ Facility emergency rating is exceeded under single contingency conditions.
- ❑ Bus voltage is not within 5% of nominal voltage under normal system conditions.
- ❑ Bus voltage is not within 10% of nominal voltage under single contingency conditions.

New generation: Facility has been identified as necessary to accommodate new generation in generation interconnection studies or related transmission service studies conducted by ATC.

Service limitation: Facility has been identified by ATC as a chronic cause for interrupting, curtailing, limiting or denying transmission service in real time.

T-D interconnection: Facility is required to interconnect to a new transmission-distribution substation needed by a distribution company served by ATC.

Condition: Facility has been identified by ATC as being in need of repair or replacement.

Stability: Facility has been identified by ATC as needed to ensure ATC dynamic stability criteria is met, or will improve stability response of generation.

Import capability: Facility will enhance import capability or address chronic limiters to the movement of power in the ATC transmission system.

Other identifiers may be used in the “need category” column to provide further explanation as appropriate in particular cases

*Table V-1
Changes to the 2003 10-Year Assessment*

Planned Additions	System Need Year	Projected In-service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Rebuild from Nordic SS to Randville SS (5 miles) of single circuit 69 kV line to double circuit 69 kV	2005	2004	2	reliability, condition	Planned	\$ 1.6
Construct a tap to Belle Plain from the Badger-Caroline 115 kV line	2004	2004	4	T-D interconnection	Planned	\$ 1.1
Uprate Rocky Run-Northpoint 115 kV line terminal equipment at Northpoint	2005	2005	1	reliability, new generation	Planned	\$ 0.06
Rebuild existing West Marinette-Menominee 69 kV line to double circuit 138/69 kV	2005	2005	2 & 4	reliability, service limitation	Planned	\$ 6.9
Convert Menominee-Rosebush 69 kV line to 138 kV	2005	2005	2 & 4	reliability, service limitation	Planned	\$ 11.4
Rebuild/reconductor Rosebush-Amberg 138 kV line	2005	2005	2 & 4	reliability, service limitation	Planned	\$ 6.8
Construct a Fox Energy-Forest Junction 345 kV line	2005	2005	4	new generation	Planned	\$ 4.5
Construct new Fox Energy 345 kV switchyard	2005	2005	4	new generation	Planned	\$ 7.1
Install a 26 MVAR capacitor bank at Hartford 138 kV substation	2004	2005	5	reliability	Proposed	\$ 1.0
Install 69 kV phase shifter or fixed reactor at Council Creek	2002	2006	1	reliability	Proposed	\$ 1.9
Construct new Gardner Park 345/115 kV substation	2006	2006	1	service limitation, reliability, import capability & Weston stability	Proposed	Included In A-W Estimate
Replace 345/115 kV 200 MVA transformer at Weston with two 500 MVA units at the Gardner Park substation	2005	2006	1	service limitation, reliability, import capability & Weston stability	Planned	Included In A-W Estimate

*Table V-1
Changes to the 2003 10-Year Assessment (continued)*

Planned Additions	System Need Year	Projected In-service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Construct Gardner Park-Stone Lake 345 kV line	1997	2006	1	service limitation, reliability, import capability & Weston stability	Planned	\$ 262.1
Install a 345/161 kV transformer at Stone Lake (temporary installation for construction outages)	2006	2006	1	reliability	Proposed	Included In A-W Estimate
Construct an Eagle River-Cranberry/Three Lakes 115 kV line	2006	2006	1	T-D interconnection	Proposed	\$ 0.3
Construct double circuit 138 kV line from Forest Junction/Charter Steel to Howards Grove	2006	2006	4	T-D interconnection	Planned	\$ 8.2
Replace the two existing 33 MVA 138/69 kV transformers at Edgewater with two 60 MVA transformers	2003	2006	4	reliability	Proposed	\$ 2.4
Replace the existing 46.7 MVA 138/69 kV transformer at South Sheboygan Falls with 100 MVA transformer	2003	2006	4	reliability	Proposed	\$ 1.3
Replace the existing 46.7 MVA 138/69 kV transformer at Mullet River with 100 MVA transformer	2003	2006	4	reliability	Proposed	\$ 1.3
Construct a Martin Road-South Fond du Lac/Ohmstead 138 kV line	2006	2006	4	T-D interconnection	Planned	\$ 1.6
Construct Clear Lake-Arnett Road 115 kV line	2007	2007	1	T-D interconnection	Proposed	\$ 2.1
Construct Venus-Metonga 115 kV line	2007	2007	1	T-D interconnections	Proposed	\$ 5.0
Uprate Rockdale to Boxelder 138 kV line	2007	2007	3	reliability	Proposed	\$ 0.3
Construct a Jefferson-Lake Mills-Stony Brook 138 kV line	2006	2007	3	reliability, T-D interconnection	Proposed	\$ 11.3

*Table V-1
Changes to the 2003 10-Year Assessment (continued)*

Planned Additions	System Need Year	Projected In-service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Construct new 69 kV line from Brooklyn to Sugar River Substation	2007	2007	3	reliability	Proposed	\$ 5.0
Construct a new Lannon Junction substation at intersection of Granville-Arcadian 345 kV, Sussex-Tamarack 138 kV and Sussex-Germantown 138 kV lines; install a 345/138 kV, 500 MVA transformer	2007	2007	5	reliability	Proposed	\$ 14.2
Install 1-40 MVAR capacitor banks at Arpin 138 kV	2008	2008	1	achieve transfer capability associated with Arrowhead-Weston	Proposed	Included In A-W Estimate
Install 6-34 MVAR capacitor banks at Gardner Park 115 kV	2008	2008	1	achieve transfer capability associated with Arrowhead-Weston	Proposed	Included In A-W Estimate
Install 4-50 MVAR capacitor bank at Arrowhead 230 kV	2008	2008	1	achieve transfer capability associated with Arrowhead-Weston	Proposed	Included In A-W Estimate
Construct a Rubicon-Hustisford 138 kV line	2008	2008	3	reliability	Provisional	\$ 4.8
Rebuild Hustisford-Horicon 69 kV to 138 kV	2008	2008	3	reliability	Provisional	\$ 2.7
Construct 138/69 kV substation at a site near Horicon and install a 138/69 kV transformer	2008	2008	3	reliability	Provisional	\$ 2.8
Construct new Central Wisconsin 345 kV substation	2009	2009	1 & 4	service limitation, reliability, import capability & Weston stability	Proposed	\$ 10.5
Construct Gardner Park-Central Wisconsin 345 kV line	2009	2009	1	service limitation, reliability, import capability & Weston stability	Proposed	\$ 86.6
Construct new 138 kV bus and 138/69 kV 100 MVA transformer at Sugar River Substation	2009	2009	3	reliability	Provisional	\$ 1.4

*Table V-1
Changes to the 2003 10-Year Assessment (continued)*

Planned Additions	System Need Year	Projected In-service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Construct new 138 kV line from Sugar River to Southeast Fitchburg Substation	2009	2009	3	reliability	Provisional	\$ 5.2
String a new 138 kV line from Clintonville-Werner West primarily on Morgan-Werner West 345 kV line structures	2004	2009	4	reliability, service limitation	Proposed	included in Morgan-Werner estimate
Reconductor a segment of the Oak Creek-Ramsey6 138 kV line	2009	2009	5	new generation	Proposed	\$ 0.1
Reconductor underground segment of Ramsey5-Harbor 138 kV line	2009	2009	5	new generation	Proposed	\$ 11.5
Reconductor Oak Creek-Allerton 138 kV line	2009	2009	5	new generation	Proposed	\$ 2.0
Expand Oak Creek 345 kV switchyard to interconnect one new generator	2009	2009	5	new generation	Proposed	\$ 18.8
Install two 345 kV series breakers at Pleasant Prairie on lines to Racine (L631) and Zion (L2221)	2009	2009	5	new generation	Proposed	\$ 2.1
Replace seven 138 kV overdutied breakers at Bluemound	2009	2009	5	new generation	Proposed	\$ 2.4
Uprate Kansas-Ramsey6 138 kV line	2009	2009	5	new generation, reliability	Proposed	\$ 0.1
Uprate Oak Creek-Ramsey6 138 kV line	2009	2009	5	new generation, reliability	Proposed	\$ 0.1
Install second 500 MVA 345/138 kV transformer at Oak Creek	2009	2009	5	new generation	Proposed	\$ 8.4
Construct an Oak Creek-Brookdale 345 kV line installing 4 mi. new structures, converting 16.2 mi. of non-operative 230 kV and 5 mi. 138 kV	2010	2010	5	new generation	Proposed	\$ 17.3

*Table V-1
Changes to the 2003 10-Year Assessment (continued)*

Planned Additions	System Need Year	Projected In service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Construct Oak Creek-St Martins 138 kV circuit #2 installing 4 mi. new structures and conductor, plus 12.6 mi. conductor on existing towers	2010	2010	5	new generation	Proposed	\$ 3.4
Construct a Brookdale-Granville 345 kV line converting/reconducting 5.6 mi. 138 kV, rebuilding 7 mi. 138 kV double circuit tower line and converting/reconducting 3 mi. 138 kV on existing 345 kV structures	2010	2010	5	new generation	Proposed	\$ 19.3
Restrung Bluemound-Butler 138 kV line (KK5051) on new 345 kV structures installed with Brookdale-Granville line	2010	2010	5	new generation	Proposed	\$ 1.1
Construct Butler-Tamarack (Carmen) 138 kV line on new 345 kV structures installed with Brookdale-Granville line	2010	2010	5	new generation	Proposed	\$ 1.0
Construct a 345/138 kV switchyard at Brookdale to accommodate two 345 kV lines, a 500 MVA 345/138 kV transformer and 4-138 kV lines plus two 138-26.2 kV transformers	2010	2010	5	new generation	Proposed	\$ 14.8
Expand 345 kV switchyard at Oak Creek to interconnect one new generator plus one new 345 kV line and 138 kV switchyard to accommodate new St. Martins line	2010	2010	5	new generation	Proposed	\$ 4.2
Construct 345 kV line from Paddock to new Sugar River 345 kV switchyard; loop Kegonsa-West Middleton 345 kV line into Sugar River	2012	2012	3	reliability, transfer capability	Provisional	\$ 119.3
Construct 345 kV Bluemound switchyard to accommodate 1-345 kV line and a 500 MVA 345/138 kV transformer	2012	2012	5	new generation	Proposed	\$ 4.8

*Table V-1
Changes to the 2003 10-Year Assessment (continued)*

Planned Additions	System Need Year	Projected In-service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Expand Oak Creek 138 kV switchyard to reconnect Units 6 and 9	2012	2012	5	new generation	Proposed	\$ 6.8
Convert and reconductor Oak Creek-Bluemound 230 kV line K862 to 345 kV and loop into Arcadian 345 kV substation	2012	2012	5	new generation	Proposed	\$ 34.8
Construct Oak Creek-Racine 345 kV line with 4 mi new structures and conductor, plus convert 9.6 mi. 138 kV line KK812 to 345 kV	2012	2012	5	new generation	Proposed	\$ 8.1
Replace 22-138 kV overdutied breakers at Harbor, Everett and Haymarket Substations	2012	2012	5	new generation	Proposed	\$ 7.7
Expand Oak Creek 345 kV switchyard to interconnect three new generators	2012	2012	5	new generation	Proposed	\$ 21.5

Table V-2
Alternative Solutions to Planned, Proposed or Provisional Additions

Primary Solution(s)	Alternate Solution(s)	Projected In-service Year	Planning Zone
Convert Pine-Grandfather-Tomahawk-Eastom 46 kV system to 115 kV and construct new Lake Nokomis-Highway 8 115 kV line	<ol style="list-style-type: none"> 1) Weston-Venus 345 kV line. 2) Venus-Crandon-Laona-Goodman-Amberg 138 kV line. 3) Venus-Crandon-Laona-Goodman-Plains 138 kV line. 4) Cranberry-Conover 138 kV line and convert Conover-Iron River-Plains to 138 kV. 5) Cranberry-Conover 138 kV line and convert Conover-Winona to 138 kV. 6) Rebuild Bunker Hill-Blackbrook 115 kV line and rebuild Blackbrook-Aurora St. with double circuit 115 kV lines. 7) Generation in upper portion of Rhinelander Loop. 	2004 & 2005	1
New Cranberry-Conover 138 kV line and Convert Conover-Iron River-Plains 69 kV to 138 kV	<ol style="list-style-type: none"> 1) Weston-Venus 345 kV line. 2) Weston-Venus-Plains 345 kV line. 3) Cranberry-Conover 138 kV line and convert Conover-Winona to 138 kV. 4) Venus-Crandon-Laona-Goodman-Plains 138 kV line. 5) Venus-Crandon-Laona-Goodman-Amberg 138 kV line. 6) Generation in upper portion Rhinelander Loop 7) Park Falls-Clear Lake 115 kV line 8) Convert Whitcomb-Aurora St. 69 kV to 115 kV 	2007	1
Two T-D interconnections: Arnett Road & Boulder Junction. New Clear Lake-Arnett Road 115 kV line and a new St. Germain-Boulder Junction 115 kV line. Both lines to be radial.	<ol style="list-style-type: none"> 1) Loop new T-D substations with a Clear Lake-Arnett Rd-Boulder Junction-Conover 115 kV line. 2) Loop new T-D substations with a Clear Lake-Arnett Rd-Boulder Junction-St. Germain 69 kV line. 3) Construct new 69 kV radial lines to Arnett Rd and Boulder Junction with 115/69 kV xfms at Clear Lake and St. Germain. 4) New Clear Lake-Arnett Rd 115 kV line and extend 115 kV line west to NSP's Park Falls substation. 	2006 & 2008	1

*Table V-2
Alternative Solutions to Planned, Proposed or Provisional Additions (continued)*

Primary Solution(s)	Alternate Solution(s)	Projected In-service Year	Planning Zone
Berlin area reinforcements: New Omro-Fitzgerald 69 kV line. Install capacitor banks at Ripon and Berlin.	1) Reconfigure N. Randolph-Ripon 69 kV line to N. Randolph-Metomen & Metomen-Ripon 69 kV lines. Cap bank installations at Berlin, Ripon and Winneconne and second 138/69 kV transformer at Metomen. 2) Convert Metomen-Ripon-Berlin 69 kV line to 138 kV with a new 138/69 kV transformer at Berlin. 3) Rebuild the Metomen-Ripon-Berlin 69 kV line to a 138-69 kV double circuit with new 138/69 kV transformer at Berlin.	2004 - 2009	1
Uprate Weston-Sherman St., Weston-Morrison-Sherman St., and Sherman St.-Hilltop 115 kV lines	1) Convert WPS's 46 kV system from Maine-Brokaw-Strowbridge-Wausau Hydro-Townline-Kelly to 115 kV. 2) Convert WPS's 46 kV system from Sherman St.-Wausau Hydro-Strowbridge-Townline-Kelly to 115 kV	2007	1
Uprate Weston-Kelly 115 kV line	1) Convert WPS's 46 kV system from Weston-Rothschild-Kelly to 115 kV. 2) Reroute/reterminate Weston end of line to new Weston 345-115 kV substation.	2006	1
Install 69 kV series reactor at Council Creek	1) Install a 69 kV phase shifter Council Creek. 2) Install a new 161/138 kV transformer at Monroe County and convert DPC's Monroe County-Council Creek 69 kV system to 138 kV.	2004	1
Construct a 0.2-mile Hiawatha to Engadine 69 kV line to relieve low voltages under contingency by removing load from the end of a 71-mile, 69 kV line.	Add capacitor bank near Newberry SS.	2003	2
Add a second 138/69 kV transformer at Straits	Replace the Straits 138/69 kV transformer with a larger size	2004	2
Construct second Hiawatha-Straits 138 kV line	Limit flows with a phase shifter and add 138 kV capacitors at Brevort or Lakehead	2007	2
Rebuild and convert one Hiawatha-Indian Lake 69 kV circuit to double circuit 138 kV	Rebuild at 69 kV and limit flows with a phase shifter	2004	2

*Table V-2
Alternative Solutions to Planned, Proposed or Provisional Additions (continued)*

Primary Solution(s)	Alternate Solution(s)	Projected In-service Year	Planning Zone
Convert North Madison 69 kV line through Sun Prairie to Reiner to 138 kV	Reconfigure Sun Prairie 69 kV system, install second 138/69 kV transformer at North Madison	2005	3
Construct a new 345 kV line from Rockdale to West Middleton	Uprate Christiana to Fitchburg 138 kV line to 319 MVA	2004	3
Construct a new 345 kV line from Rockdale to West Middleton	Reconductor Kegonsa to Christiana 138 kV line	2005	3
Construct a new 345 kV line from Rockdale to West Middleton	1) Convert Kegonsa to Femrite to 138 kV, close the 138 kV loop from Femrite to Sprecher, convert the Sycamore to Sprecher line to 138 kV 2) Install Rockdale to Sprecher/Femrite 138 kV double circuit	2008	3
Construct a new 345 kV line from Rockdale to West Middleton	1) Construct a new 345 kV line from North Madison to West Middleton 2) Rockdale to Sprecher/Femrite 138 kV double circuit 3) Numerous 138 kV and 69 kV capacitor banks, reconductor Kegonsa to Christiana, reconductor Fitchburg to Christiana, add a second 138/69 kV transformer at North Madison, add a third 345/138 kV transformer at North Madison, reconductor or uprate North Madison to Sycamore 138 kV line, install a second 138/69 kV transformer at Kegonsa, reconductor all three East Campus to Blount 69 kV lines, reconductor Blount to Gateway 69 kV line.	2009	3
Convert 69 kV line from West Middleton to Spring Green to 138 kV and Construct a new 345 kV line from Rockdale to West Middleton	Install several capacitor banks on 69 kV buses and on 138 kV buses	2008	3
Install line between Spring Green and Prairie du Sac to off load this line	Install parallel transformers at Portage and North Madison	2009	3
Construct a Canal-Dunn Rd 138 kV line and add a 138/69 kV transformer at Dunn Rd	1) Add a third 138/69 kV transformer at Canal 2) Add generation to the 69 kV system in Northern Door County 3) Replace Canal 138/69 kV transformers 1 and 2	2007	4

*Table V-2
Alternative Solutions to Planned, Proposed or Provisional Additions (continued)*

Primary Solution(s)	Alternate Solution(s)	Projected In-service Year	Planning Zone
Add two 16.3 MVAR capacitor bank at Canal 69 kV in 2004	<ol style="list-style-type: none"> 1) Rebuild Pulliam-Brusbay-Sawyer-Canal 69 kV line for 138 kV 2) Construct a 138 kV line from Egg Harbor to Menominee under the bay of Green Bay and operate at 69 kV 3) Construct a 138 kV line from Sister Bay to Escanaba under the bay of Green Bay and operate at 69 kV 4) Add generation to the 69 kV system in Door County 	2004	4
Add 138 kV conductor for Ellinwood-Sunset Point 138 kV on existing structures	<ol style="list-style-type: none"> 1) Replace Ellinwood 138/69 kV transformer 2) Add a third Ellinwood 138/69 kV transformer 	2005	4
Construct 138 kV line from Forest Junction-Cedarsauk to Howards Grove	<ol style="list-style-type: none"> 1) Construct a 138 kV line from Erdman to Howards Grove 2) Construct a 69 kV line from Erdman to Howards Grove 	2006	4
Construct the Morgan-Werner West 345 kV line and construct a 345/138 kV switchyard at a new Werner West SS; install a 345/138 kV transformer. Loop existing Rocky Run to North Appleton 345 kV and existing Werner to White Lake 138 kV lines into Werner West	<ol style="list-style-type: none"> 1) Construct a 345 kV line from Morgan to N. Appleton, add a fourth 345/138 kV transformer at N. Appleton, uprate the Kaukauna Central Tap-Melissa-Tayco 138 kV line, uprate Butte des Morts 138 kV bus tie, uprate Casaloma-Ellington-N Appleton 138 kV line. 2) Add a fourth 345/138 kV transformer at N. Appleton, uprate the Kaukauna Central Tap-Melissa-Tayco 138 kV line uprate Butte des Morts 138 kV bus, uprate Casaloma-Ellington-N Appleton 138 kV line, uprate Ellington 138 kV bus, uprate Morgan-White Clay 138 kV line, and add a 14.4 MVAR capacitor bank at Casaloma 138 kV 	2009	4
Construct a second Dunn Rd-Egg Harbor 69 kV line	<ol style="list-style-type: none"> 1) Construct a new 138 kV line from Dunn Rd to Egg Harbor 2) Add generation to the 69 kV system in northern Door County 	2007	4
Rebuild Crivitz-High Falls 69 kV double circuit line	<ol style="list-style-type: none"> 1) Construct 25.5 mile 138 kV line from Amberg to Goodman 2) Increase clearances on the Crivitz-High Falls 69 kV double circuit line and add a 5.4 MVAR capacitor bank at High Falls 3) Construct the Laona-Goodman-Amberg 138 kV line 	2007	4
Replace Mullet River and S. Sheboygan Falls 138/69 kV transformers with 100 MVA units and replace Edgewater 138/69 kV transformers with 60 MVA units	<ol style="list-style-type: none"> 1) Tap the Forest Junction-Cedarsauk 138 kV line to Sheboygan Falls and add a 138/69 kV transformer. 2) Construct a 138 kV line to the 69 kV Plymouth Sub #2 and convert Plymouth Sub#2 to 138 kV 3) Construct 2.5 miles of 138 kV line from Lodestar to Sheboygan Falls and install a 138/69 kV, 60 MVA transformer at Sheboygan Falls 	2006	4

*Table V-2
Alternative Solutions to Planned, Proposed or Provisional Additions (continued)*

Primary Solution(s)	Alternate Solution(s)	Projected In-service Year	Planning Zone
Install two 345 kV series breakers at Pleasant Prairie on lines to Racine (L631) and Zion (L2221)	Reconfigure 345 kV lines on bus sections 3 and 4. Reconfigure Pleasant Prairie 345 kV straight bus into ring bus. Construct a 345 kV bus at Bain SS.	2007	5
Construct Rockdale-Concord-Bark River-Lannon Junction 345 kV line with 345/138 kV transformers at Concord, Bark River and Lannon Junction	<ol style="list-style-type: none"> 1) Construct a 345 kV line from Rockdale-Concord-St Lawrence 2) Add a 345/138 kV transformer at St. Lawrence 3) Add a 345/138 kV transformer at Concord 4) Add a 138 kV switching station at Lannon Junction site 	2008/10	3 & 5
Construct Rockdale-Concord-Bark River-Lannon Junction 345 kV line with 345/138 kV transformers at Concord, Bark River and Lannon Junction	<ol style="list-style-type: none"> 1) Construct a Bark River-Concord 138 kV line 2) Construct a Bark River- Hartford 138 kV line 3) Add a 138 kV switching station at Lannon Junction site 4) Rebuild existing Rockdale-Concord-Cooney-Summit 138 kV to double-circuit 138 kV; construct 8-position ring buses at Jefferson and Concord 5) Uprate Stonybrook-Boxelder 138 kV 6) Install 32 MVAR capacitor bank at Summit and 75 MVAR at Concord 138 kV 	2008/10	3 & 5
Construct second Wempletown-Paddock 345 kV line	Install 67 MVA transformer at Galena as an interim measure	2004	3

Figure V-1 Zone 1 Transmission System Solution Alternatives

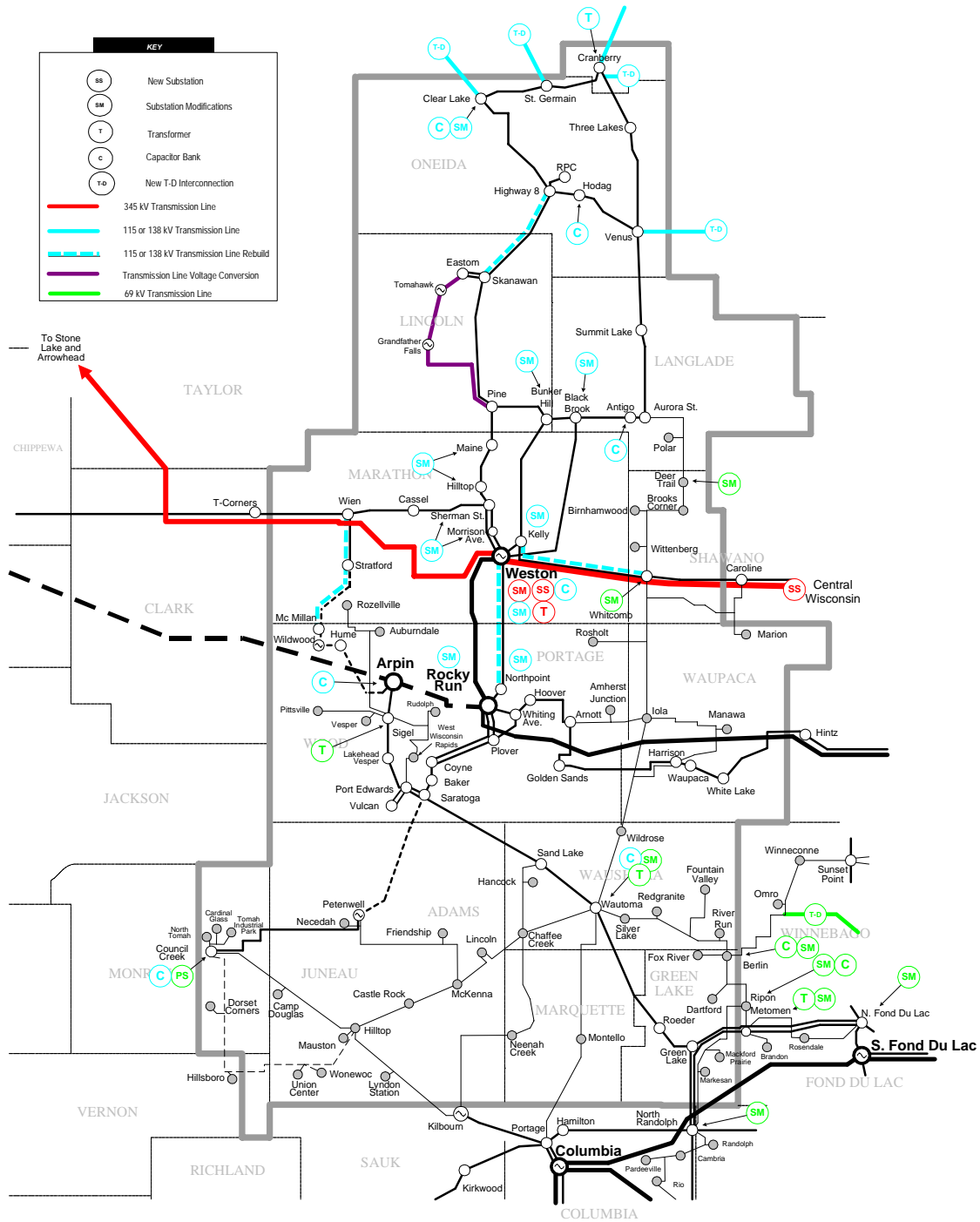
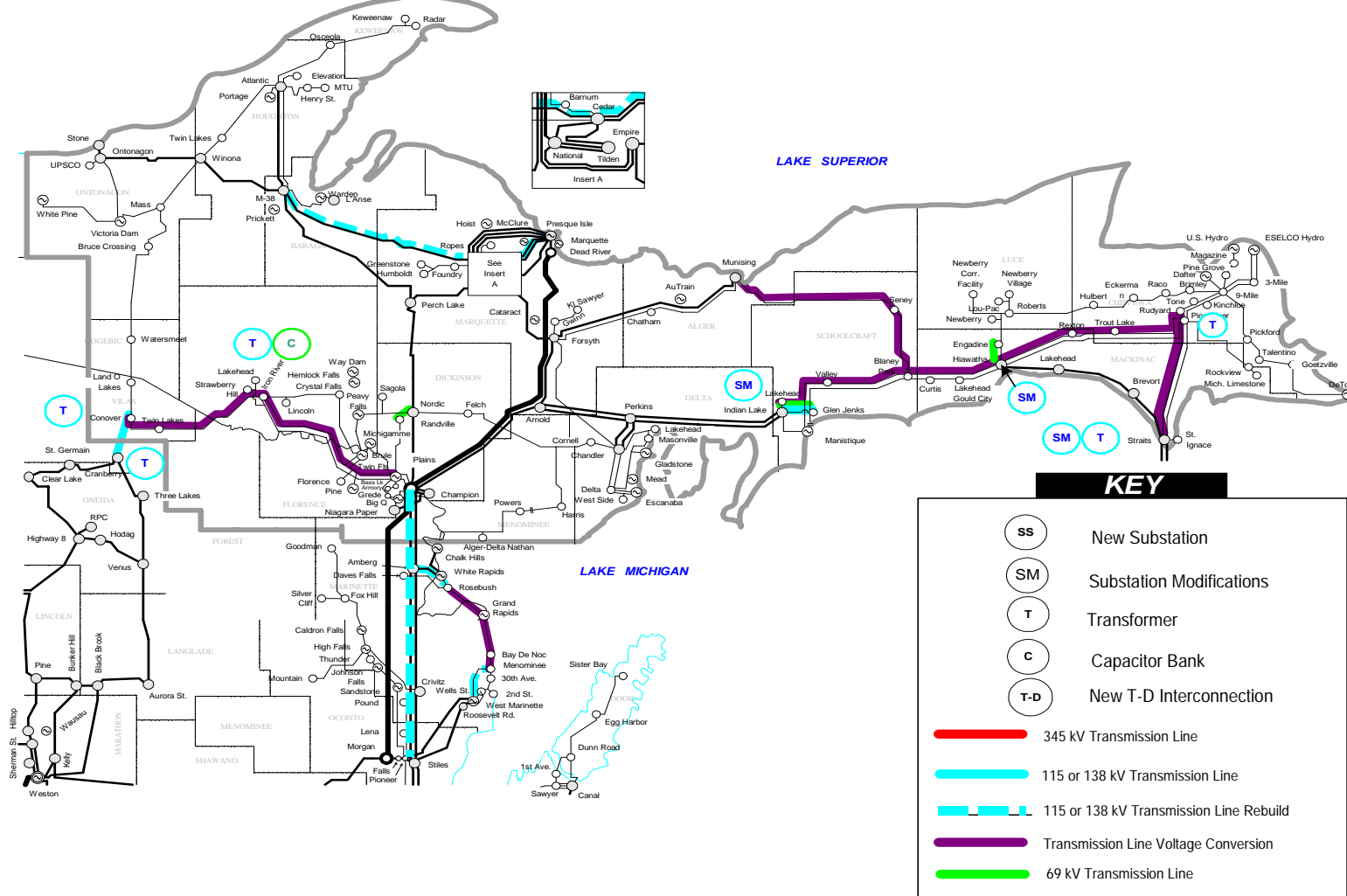


Figure V-2 Zone 2 Transmission System Solution Alternatives



KEY

- New Substation
- Substation Modifications
- Transformer
- Capacitor Bank
- New T-D Interconnection
- Phase Shifter

- 345 kV Transmission Line
- 115 or 138 kV Transmission Line
- 115 or 138 kV Transmission Line Rebuild
- Transmission Line Voltage Conversion
- 69 kV Transmission Line

Figure V-3
Zone 3 Transmission System Solution Alternatives

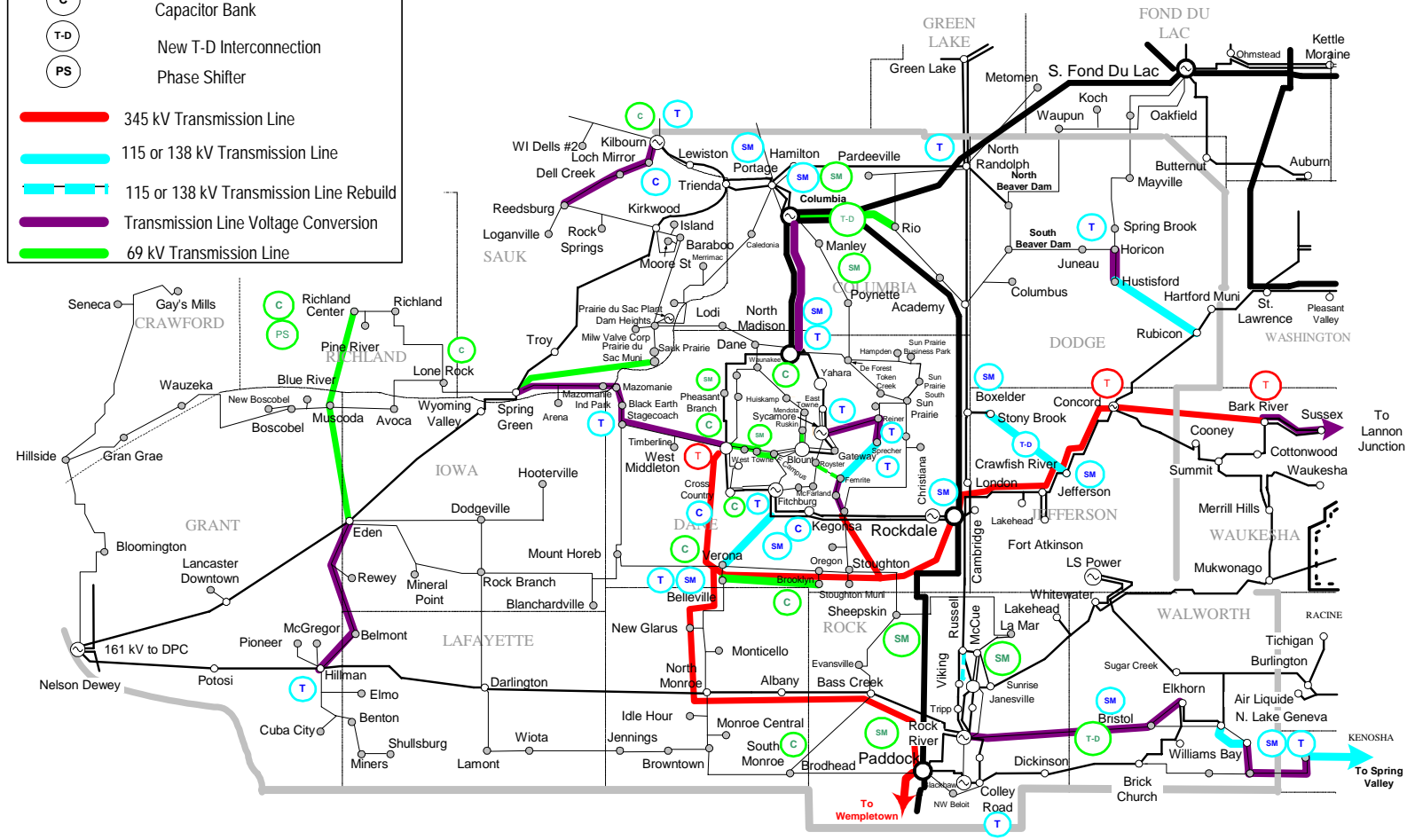
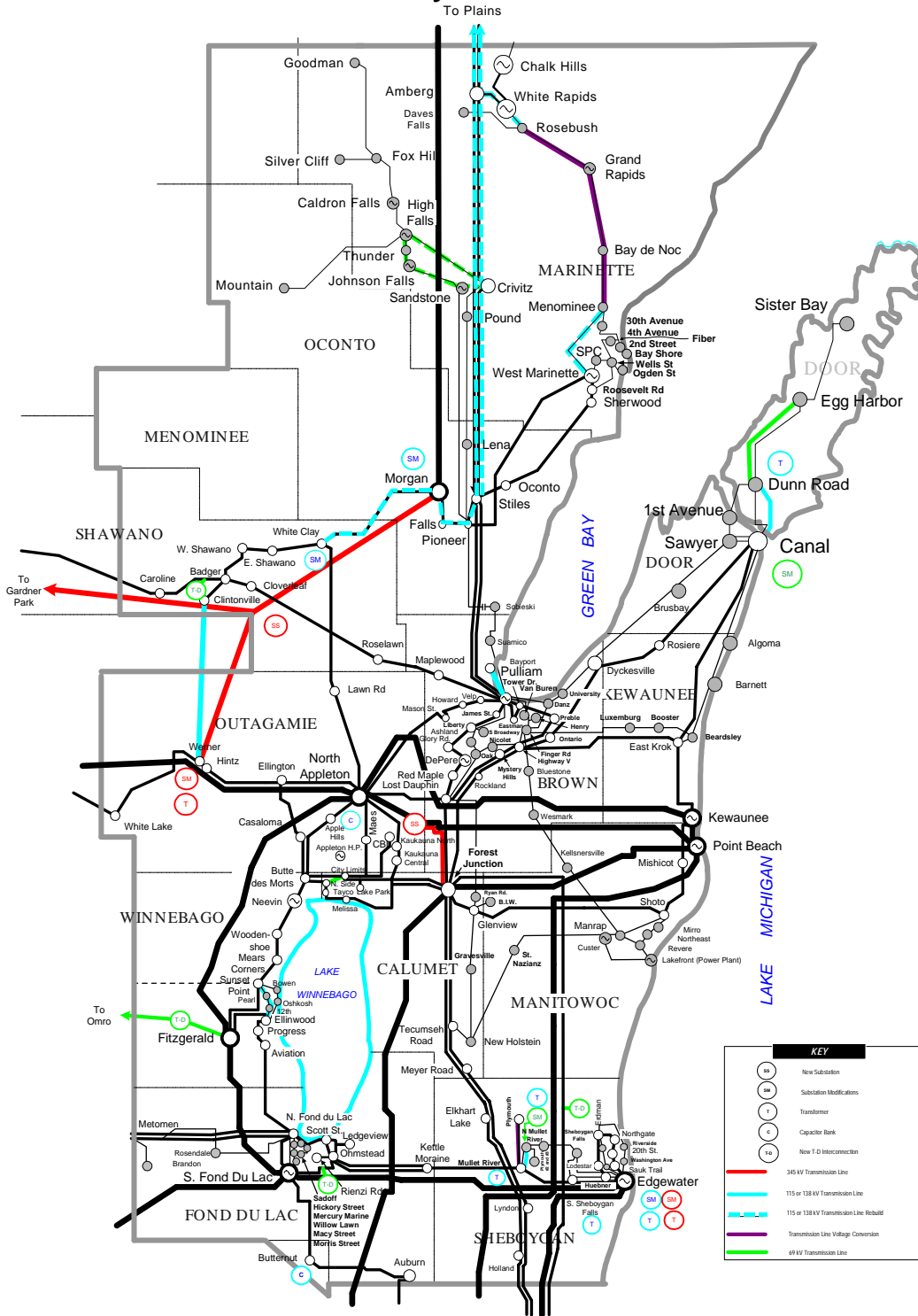
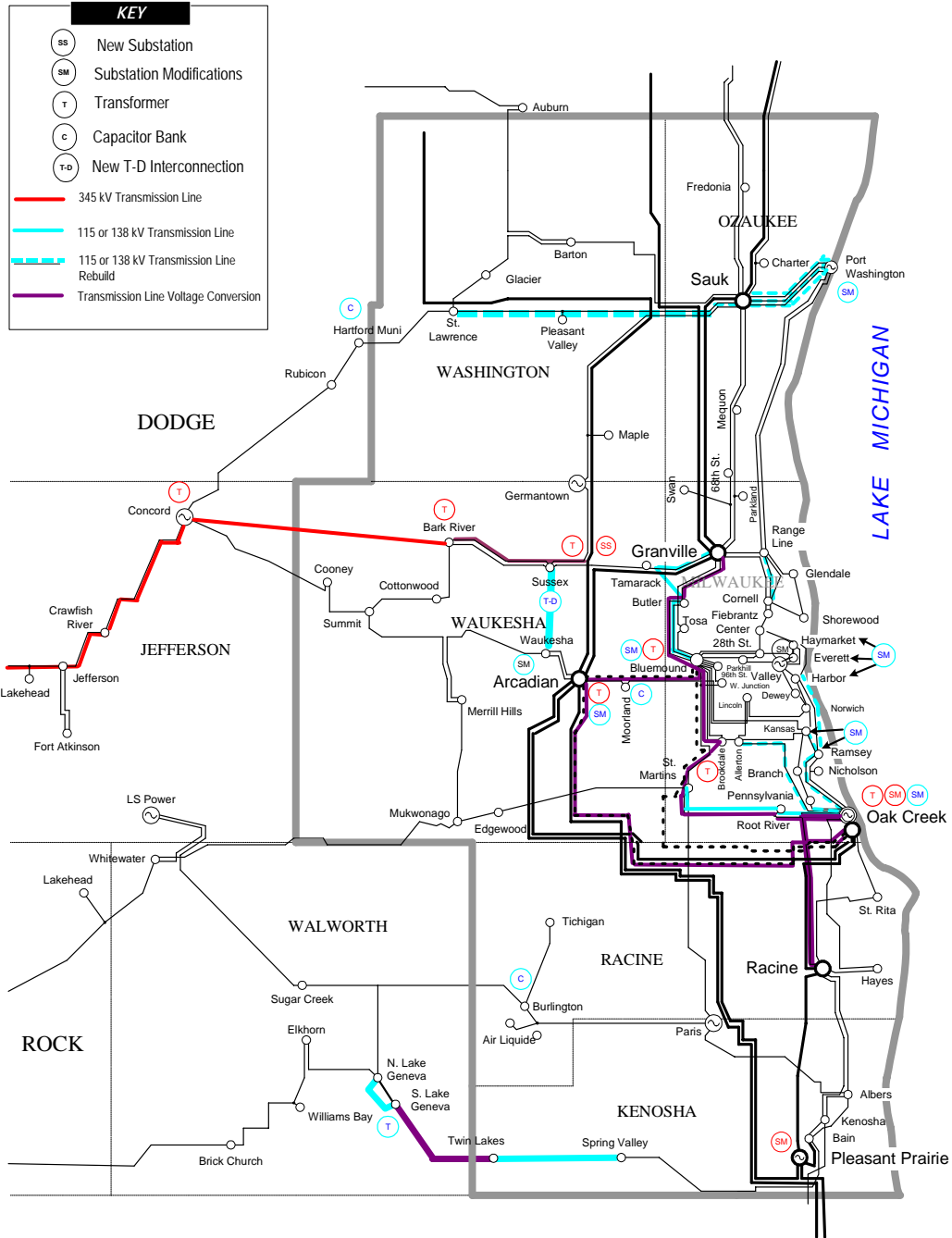


Figure V-4 Zone 4 Transmission System Solution Alternatives



KEY	
(SM)	New Substation
(M)	Substation Modifications
(T)	Transformer
(C)	Capacitor Bank
(I)	New T.D. Interconnection
(H)	
(S)	
(E)	
(F)	
(G)	
(H)	
(I)	
(J)	
(K)	
(L)	
(M)	
(N)	
(O)	
(P)	
(Q)	
(R)	
(S)	
(T)	
(U)	
(V)	
(W)	
(X)	
(Y)	
(Z)	

Figure V-5 Zone 5 Transmission System Solution Alternatives



Section VI

ACCESS

Transmission access is the ability to transfer power into, out of, through and within the transmission system without impediments. **External access** is the ability to transfer power from outside the ATC footprint to within the footprint without impediments. **Internal access** is the ability to transfer power within the ATC footprint without impediment, whether from new or existing power plants.

A combination of external access and internal access is needed for customers to operate most efficiently. External access alone is insufficient if the internal system cannot accommodate transfer of power within ATC to where it is needed. Internal access alone is insufficient if power is available outside of ATC's footprint but can't be transferred to ATC customers. A sufficient blend of external and internal access allows ATC's customers to reduce the cost of supplying electricity to their customers. To date, ATC has focused most of its attention on reliability issues and chronic limitations within the ATC system. The projects that ATC has completed that addressed chronic limitations have provided modest increases in transfer capability into the ATC system. ATC is now in a position to focus on identifying projects that are primarily aimed at increasing access.

Background

From 2001 through 2003, numerous projects have been completed to address chronic limitations within the ATC footprint to providing transmission service. Some of these key projects include:

- ❑ Rockdale 345/138 kV transformer (Zone 3)
- ❑ Whitewater-Mukwonago 138 kV line reconductor (Zones 3 and 5)
- ❑ Forest Junction 345/138 kV transformer (Zone 4)
- ❑ Saukville-Granville 138 kV line rebuild (Zone 5)
- ❑ Blackhawk-Colley Road 138 kV line reconductor (Zone 3)
- ❑ Christiana-Kegonsa 138 kV line reconductor (Zone 3)
- ❑ Highway V-Preble 138 kV line uprate (Zone 4)

In addition, ATC is pursuing numerous other projects that will improve transmission system transfer capability and access, both for importing power from neighboring entities and accommodating transactions between utilities within the ATC footprint:

- ❑ Arrowhead-Weston 345 kV line
- ❑ Wempletown-Paddock 345 kV line
- ❑ Plains-Stiles 138 kV line rebuild
- ❑ Hiawatha-Indian Lake 69 kV line rebuild/conversion
- ❑ Morgan-Werner West 345 kV line
- ❑ Lannon Junction-Rockdale 345 kV line
- ❑ Morgan-White Clay 138 kV reconductor
- ❑ Morgan-Stiles 138 kV rebuild

These projects will substantially improve the ability of ATC's customers to transact business in the electricity market. However, from a utility customer perspective, these are interim steps and will not provide sufficient access to markets outside of the ATC footprint for the longer term. Over time, load growth and system changes such as the addition of new power plants will use up gains in transfer capability realized from projects like those listed above. In addition, while strengthening the transmission system within ATC's footprint does, in some cases, improve our customers' ability to import power and transact among themselves, additional ties to neighboring utilities will be needed to provide any substantial gain in ATC system transfer capability.

ATC has been performing initial analyses to address the issue of improving access. In the 2003 10-Year Assessment, ATC provided examples of projects that would increase existing system transfer capability by up to 3,000 megawatts in 1,000-megawatt increments. These examples illustrated the magnitude of projects that would be required to meet the prescribed transfer capability increases. However, the analyses conducted did not address reliability benefits, economic benefits or strategic benefits to customers within the ATC footprint.

Access Value Proposition

The concept of improving access and identifying its value to customers is multi-faceted. First, the issue of defining what access *is* needs be addressed. Second, the issue of what level of access is justified needs to be addressed, based on the value expected to be derived. From there, the issues of defining an appropriate transfer capability target, identifying potential projects to attain that target as well as the costs and benefits and impacts (both environmental and socio-economic) of various alternatives, coordination between state regulatory agencies, and assessing the effect of regional planning and pricing initiatives all follow.

Transmission access

Each component of transmission access – external and internal – is critical to users of the transmission system. They are interrelated. Transmission access implies economic benefits, that is, the ability to buy and sell electricity without impediment, which results in lower energy costs to consumers. However, the process of improving access generally has impacts beyond economic benefits. To the extent transmission facilities are constructed to improve access, in virtually all instances reliability is also improved to some degree. Similarly, certain projects conceived to address reliability issues may also improve external or internal access, or both.

Among ATC customers, the key access issue is gaining greater access to power markets external to ATC. However, internal access must also be improved in order to fully realize anticipated benefits from increasing external access. Bringing power in from outside is of no benefit if it can't be delivered to customers throughout ATC's service territory.

All of the projects ATC has completed to date have been contained within the ATC system footprint. Various projects have been implemented to improve external access by eliminating internal constraints (chronic limiter). Several of those projects have also improved internal transfer capability between ATC customers. However, in order to realize significant improvements in external access, new transmission lines extending across ATC's boundaries, combined with key additional internal projects, will be required. This conclusion leads to the following questions:

- ❑ *What is the appropriate target for improving external access?*
- ❑ *How can this external access target be achieved?*
- ❑ *What specific transmission projects will yield the greatest external access gains?*
- ❑ *What specific transmission projects will yield the greatest economic benefit to our customers?*
- ❑ *What reliability gains can be realized by projects designed to improve external access?*
- ❑ *What efficiency gains can be realized by projects designed to improve external access?*
- ❑ *What strategic benefits are realized by ATC and its customers by implementing specific transmission projects?*

Value of Increasing Access

The identification of the appropriate target level for external access is a complex issue. An appropriate target level for external access should ultimately be determined by the value associated with expanding the transmission system. However, the value of expanding the transmission system goes well beyond simply increasing access. Increasing access to certain markets may yield greater economic benefits to ATC customers than increasing access to other markets. Also, increasing external access will virtually always result in gains in system reliability and efficiency. Improved reliability and efficiency also provide value to customers. Further, there may be strategic benefits realized by certain expansion projects that can't be realized by other projects.

Economic value of increasing access: The value to ATC customers of increasing access to external markets can be analyzed and evaluated quantitatively. This can be done by employing analytical models that determine the most economic dispatch of generation within transmission system security constraints. These models, referred to here as SCED (Security Constrained Economic Dispatch) models, have the capability to compute a projected cost reduction associated with different system expansion alternatives, different future scenarios, etc. ATC is developing the capability to conduct these types of analyses, in part, so that the cost benefits of various access improvement alternatives can be projected. ATC will be performing and reporting on such analyses as part of the 2004 Assessment activities.

Value of improving reliability: There are numerous potential benefits associated with improving reliability in the course of improving external access. A few examples include:

- ❑ Deferring or eliminating the need for reliability-based investments that would otherwise be required
- ❑ Reducing the need for generation redispatch during maintenance outages or sustained forced outages
- ❑ Reducing or eliminating the need for complex operating guides
- ❑ Providing additional operating margin during unforeseen multiple outages

The value of these benefits must be determined on a case-by-case basis, and except for the first example, is not easily quantified in dollars. These types of benefits should be taken into consideration, however, when evaluating access project alternatives.

Another measure of reliability improvement can be obtained by conducting probabilistic planning studies that measure the expected unserved energy (EUE), or change in EUE, associated with different access project alternatives. This is accomplished with software that determines the

minimum load reduction required to ensure that all thermal and voltage criteria are met for all single contingencies and double contingencies. While there is no definitive way to translate EUE into a monetary value, the EUE measure provides a quantitative measure of the relative reliability benefits of access project alternatives. ATC is developing the capability to perform such analyses. ATC will be performing and reporting on such reliability analyses as part of the 2004 Assessment activities.

Value of improving system efficiency: The benefits associated with improving system efficiency are clear:

- ❑ To the extent transmission system losses at the time of system and control area peak demands are reduced, the amount of installed capacity required to meet those capacity losses plus reserves is reduced. While there is no definitive industry-accepted practice to quantify this benefit, reasonable assumptions about the cost of installed generating capacity provides a reasonable estimate of the value of reducing system losses at peak.
- ❑ To the extent transmission system losses are reduced throughout the year, the amount of energy produced or purchased to meet energy loss requirements is reduced. Again, while there is no definitive industry-accepted practice to quantify this benefit, reasonable projections of the amount of loss reduction at various times during the year and the price of energy during those periods of times can provide a reasonable estimate of the value of reducing system energy losses.

ATC will be performing and reporting on such transmission loss analyses as part of the 2004 Assessment activities.

Strategic benefits: Strategic benefits may be realized with certain access improvement project alternatives, including:

- ❑ Establishing transmission infrastructure in areas where the existing infrastructure is weak and incapable of accommodating any significant load or generation additions. This strategy can potentially enable communities to attract new industry, create jobs and bolster local economies. This strategy also can potentially enable new forms of generation to be developed that are in demand.
- ❑ Facilitating the delivery of certain prospective resources that are in demand by customers (e.g., renewable resources developed outside of ATC's boundaries).
- ❑ Enhancing the value of the existing transmission system by reducing the burden on the system when transferring greater amounts of power into or through the ATC system.
- ❑ Enhancing the value of other planned transmission expansion projects, whether they are external or internal.

Preliminary Transfer Capability Analyses

Since the 2003 10-Year Assessment, ATC has begun to look at the issue of improving access by conducting in-depth analyses that look at how the direction of system expansion affects the transfer capability increase that can be achieved. Results of some initial analyses are described below.

Directional Analysis

For this Update, ATC took the next step of determining how expansion in various directions compares from the perspective of impact on import capability. ATC expects that the information provided here will begin to identify what is needed to comprehensively address the issue of improving access. The results of this analysis should be considered preliminary and are included to provide the foundation for initial discussions with customers and stakeholders. ATC has not refined any of these proxy alternatives to optimize import capability or system performance.

Methodology

The analysis presented in this section is limited to five strategic proxy projects representing five potential directions for system expansion:

- ❑ South (Illinois)
- ❑ Southwest (Iowa)
- ❑ West (Minnesota)
- ❑ Northeast (Ontario)
- ❑ East (Michigan)

The proxy projects were developed based on various analyses performed since the release of the 2003 10-Year Assessment.

The cost estimates for these projects and the associated “next fixes” represent general screening level cost estimates. Cost estimates for new transmission lines assumed the use of single-circuit steel poles on new 150-foot rights-of-way. Cost estimates for facilities outside of the ATC footprint were calculated using the same assumptions or were based on preliminary conversations with the affected neighboring transmission owner. Detailed cost estimates for specific projects and routes may differ from these very preliminary figures.

The analysis was performed using a linear analysis tool in the Power Technologies, Inc. Managing and Utilizing System Transmission software. This software used industry-wide for transfer capability simulations. In this analysis, a transfer distribution factor was used to determine whether facility overloads are affected by increased power transfers from one of the directions above into the ATC service territory.

The transfer distribution factor impact limits used in this analysis were:

- ❑ 3% for all facilities in the network analysis
- ❑ 3% for MISO-monitored single outage flowgates
- ❑ 5% for MISO-monitored no outage flowgates

A list of relevant impacts on MISO-monitored flowgates is supplied for each proxy project and the base case scenario (i.e. no strategic project added). Transfers were not examined on a control area to control area basis; therefore, the results obtained for specific source-sink pairs may be different.

The power flow model used in this analysis was developed from the Summer 2012 base case from the 2003 10-Year Assessment. For the first valid limit to power transfers identified for each proxy project, an appropriate transmission solution was developed and the analysis was rerun with the solution implemented to determine the next limit. For each scenario, the first two valid limits were identified and solutions were developed to mitigate these limits. The final run for each scenario included the two transmission solutions, and the subsequent new valid limit was identified.

Key Assumptions

The base case contains all planning projects needed to mitigate Summer 2012 overload and voltage violations except as noted below. The import capabilities identified in this analysis are dependent on the inclusion of these projects.

The base case was modified to reflect updated information for load forecasts, control area interchange and major transmission projects. One major project was eliminated from the model to avoid unduly biasing certain directions, and nine major projects were added to the base case power flow model. These changes include facilities required for confirmed transmission service requests included in the model. The following facilities were either excluded from or added to the 2012 base case from the 2003 10-Year Assessment:

Facilities excluded:

- ❑ West Middleton-Rockdale 345 kV line with a 345/138 kV transformer at West Middleton
- ❑ Duplicate Blount-Ruskin 69 kV circuit

Facilities added:

- ❑ Second Wempletown-Paddock 345 kV circuit
- ❑ Weston-Central Wisconsin 345 kV line
- ❑ Rockdale-Lannon Junction 345 kV line
- ❑ Fox Energy Generation interconnected to the Point Beach-N. Appleton 345 kV line and Fox Energy-Forest Junction 345 kV line
- ❑ West Marinette-White Rapids 69 kV line conversion to 138 kV and White Rapids-Amberg 138 kV line rebuild
- ❑ Plains-Stiles 138 kV line rebuild
- ❑ Cranberry-Conover 138 kV line with a 138/115kV transformer at Cranberry
- ❑ Conover-Twin Lake-Iron River-Plains 69 kV line conversion to 138 kV and a 138/69 kV transformer at Conover

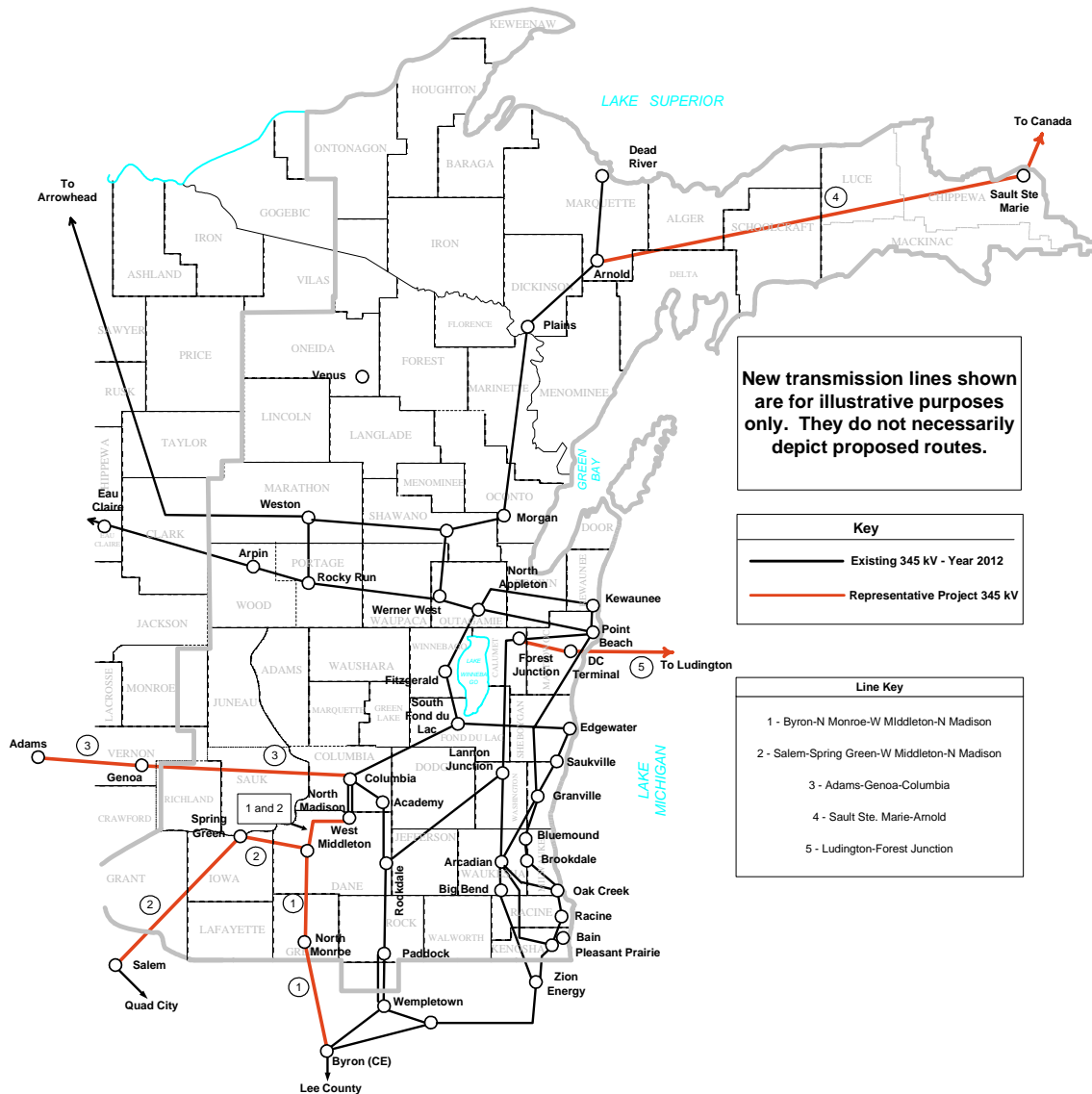
- Morgan-White Clay 138 kV line

Description of Representative Proxy Projects

The five projects examined in this section correspond to five geographic directions ATC could reasonably pursue for a new extra-high voltage (typically 345 kV) transmission interconnection. Only extra-high voltage projects were considered for the major projects in this analysis. However, ATC recognizes that extra-high voltage facilities are not the only alternatives available to meet future import requirements. Relevant alternatives to extra-high voltage facilities will be examined in the analysis performed for the 2004 10-Year Assessment.

Figure VI-1

Representative Access Projects



The five representative proxy projects, as shown on the map in Figure VI-1 are :

1. **South:** Byron–North Monroe–West Middleton–North Madison 345 kV
2. **Southwest:** Salem–Spring Green–West Middleton–North Madison 345 kV
3. **West:** Adams–Genoa–Columbia 345 kV
4. **Northeast:** Sault Ste. Marie–Arnold 345 kV
5. **East:** Ludington–Forest Junction combined DC and 345 kV AC project

Project number 4 above would include either a DC tie or a phase shifting transformer at or near Sault Ste. Marie. However, for this analysis, the system in Ontario was not included in the model and the Sault Ste. Marie bus was modeled as an injection point for the transfers. For project number 5, a special source subsystem was created to mimic the DC sink and DC source points in the interconnected system.

Network Analysis

The results presented in Figures VI-2 and VI-3 reflect the relative performance of the proxy projects. Figure VI-2 gives a visual representation of the increased import capability for each scenario. Figure VI-3 provides a comparison of the improved import capability versus the project cost. Table VI-1, below, summarizes this information.

Table VI-1
Costs and Import Capability for each Representative Project

Project	Total Cost (Millions)	Total WUMS Simultaneous Import Capability (megawatts)
Base case – no major project added	\$30	3,974
1 South: Byron – N. Madison	\$142	4,783
2 Southwest: Salem – N. Madison	\$223	4,802
3 West: Adams – Columbia	\$244	4,420
4 Northeast: Sault Ste. Marie – Arnold	\$262	3,897
5 East: Ludington – Forest Junction	\$332	4,007

Figure VI-2

**Comparison of Representative Projects
Access Project - Phase I Analysis**

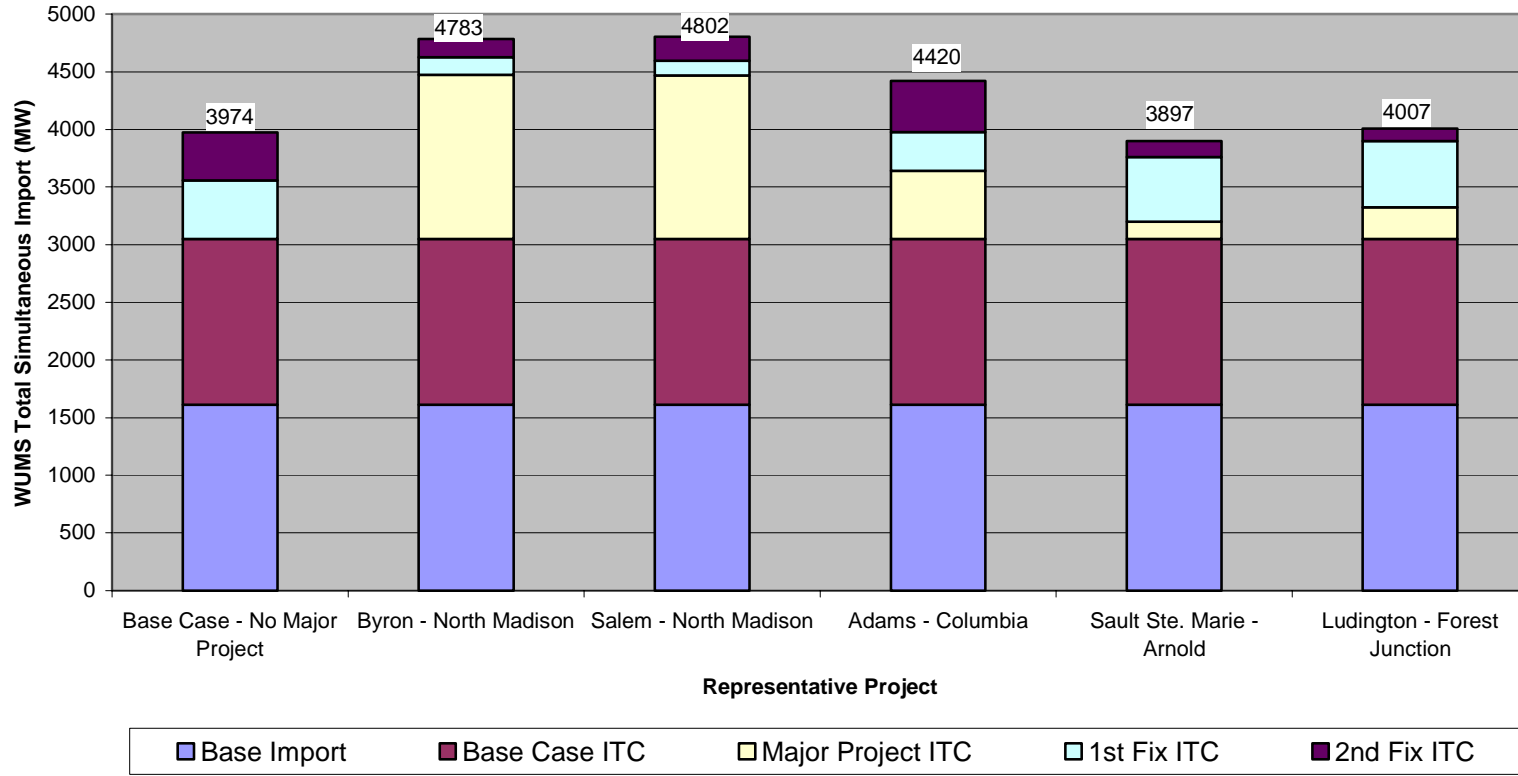
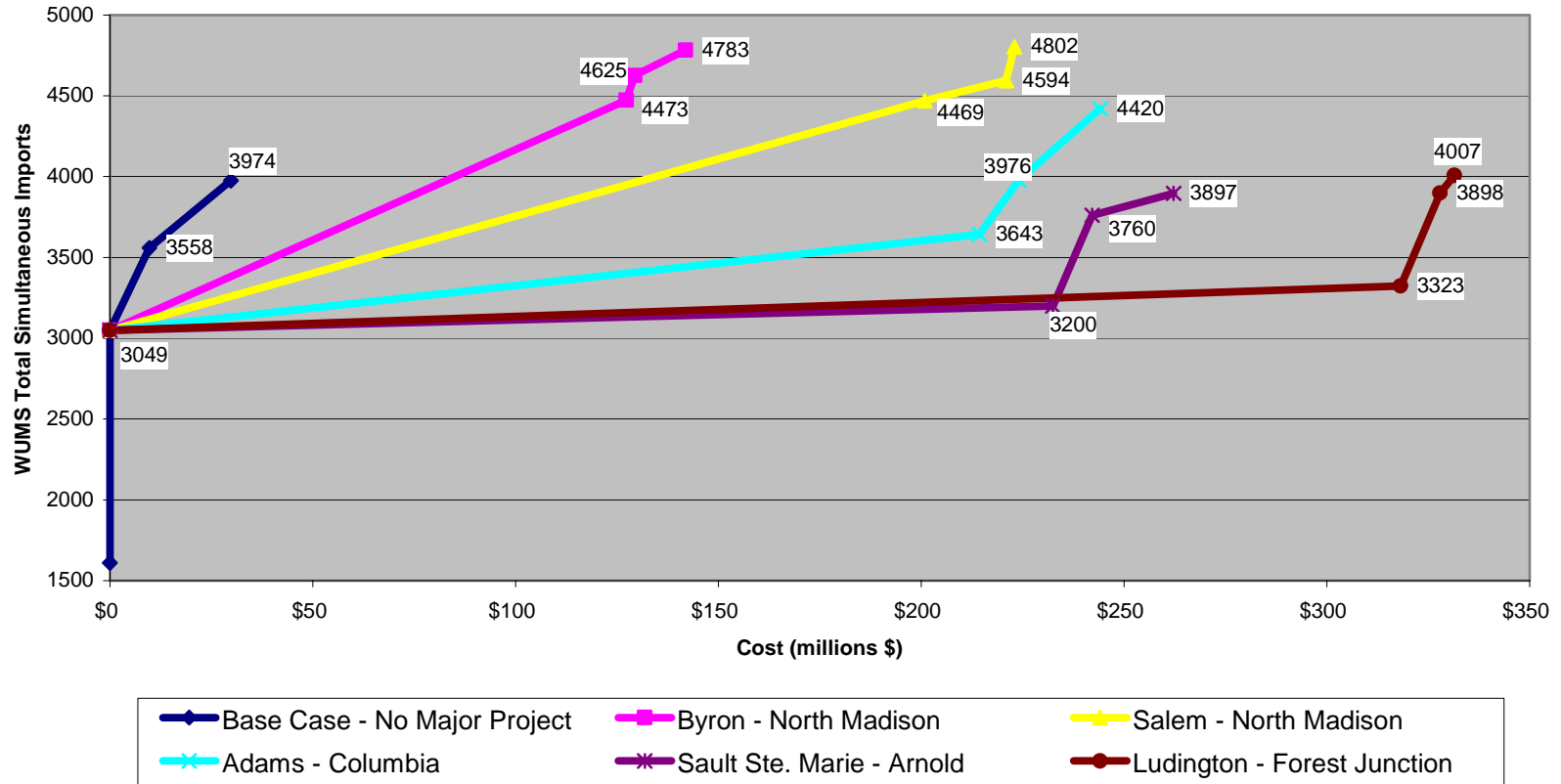


Figure VI-3

**Comparison of Representative Projects
Access Project - Phase I Analysis**



MISO Flowgate Analysis

In addition to the network analysis described before, analysis was also performed on the flowgates MISO incorporates in their Available Flowgate Capacity process. The two tables below list the flowgates that were impacted at greater than 5% for no outage flowgates and 3% for single outage flowgates. Table VI-2 lists the impacted flowgates within ATC’s service territory and Table VI-3 lists the impacted flowgates outside of ATC’s service territory. Although flowgate capability was not calculated due to the long-term horizon considered in this analysis, the flowgate impacts illustrated here may dictate that additional supplementary projects are required to achieve the indicated import capability.

Table VI-2
Percent Impact of Transfer on MISO Monitored Flowgates (ATC only)

Chronic TLR Flowgates Highlighted in Yellow

Flowgate	Type	% Base case	% Byron-North Madison	% Salem-North Madison	% Adams-Columbia	% Sault Ste Marie-Arnold	% Ludington-Forest Junction
100:ABGSTLMORPLN	OTDF					3.31	
3006:EAU_ARP_ATC	PTDF	12.07	11.72	11.50	10.51	9.36	9.38
3009:EAUARPWMPPAD	OTDF	12.27	11.85	11.65	10.65	9.55	9.55
3012:PADXFMPADROE	PTDF	8.37	6.95	7.78	8.01	7.74	7.15
3015:NED_T1WEMPAD	OTDF	5.07	4.13	4.14	4.24	4.71	4.57
3016:NED_T1EARP_G	OTDF	5.47	4.89	4.51	4.22	4.94	4.84
3017:CASNEDWEMPAD	OTDF	4.28	3.44	3.19	4.09	3.80	3.53
3018:EAUARPPRIBYR	OTDF	12.11	11.78	11.57	10.78	9.44	9.51
3236:WEMPADZIOARC	OTDF	8.84	7.28	8.19	8.44	8.14	7.45
3237:WEMPADZIOPLP	OTDF	11.55	9.42	10.65	10.99	10.56	9.47
3238:WEMPADCHESIL	PTDF	8.37	6.95	7.78	8.01	7.74	7.15
3239:WEMPADEA_ATC	OTDF	8.80	7.31	8.11	8.28	8.08	7.49
3240:ZIOPLPZIOARC	OTDF	40.65	38.15	38.51	38.87	35.77	28.92
3241:ZIOPLPWP_ATC	OTDF	34.72	32.13	32.92	33.28	30.89	25.59
3242:ZIOARCZIOPLP	OTDF	26.40	24.31	24.69	25.05	23.01	18.26
3243:ZIOARCWEMPAD	OTDF	12.18	11.12	11.40	11.56	10.42	7.98
3527:PLPRACWEMPAD	OTDF	18.80	17.28	17.65	17.88	16.17	12.60
4043:TCRWIEEARP_G	OTDF	4.00	3.88	3.79	3.32	3.06	3.15
4047:NED_T1ARRN_G	PTDF						4.08
4048:WEMPADARRN_G	PTDF	8.37	6.95	7.78	8.01	7.74	7.15
63029:WEMPADEAUARP	OTDF	8.82	7.32	8.13	8.29	8.09	7.50
65031:PLNAMB MORPLN	OTDF					4.99	
65067:PLPARCPLRRAC	OTDF	13.97	12.79	12.99	13.18	11.69	8.55
65068:PLPARCZIOARC	OTDF	9.36	8.53	8.66	8.80	7.72	5.44
Notes:							
OTDF: Contingent flowgate; PTDF: Non-contingent flowgate							

Table VI-3

Percent Impact of Transfer on MISO Monitored Flowgates (non-ATC only)

Chronic TLR Flowgates Highlighted in Yellow

Flowgate	Type	Control Area	% Base case	% Byron-North Madison	% Salem-North Madison	% Adams-Columbia	% Sault Ste Marie-Arnold	% Ludington-Forest Junction
2008:DUMSTLDUMWIL	OTDF	AEP/NIPS	4.34	4.37	4.19	4.03	4.02	
2336:BTHPALCOOPAL	OTDF	AEP/MECS						4.65
2338:COOPALTBARG	OTDF	AEP/MECS						3.09
2339:BTNPALTBARG	OTDF	AEP/MECS						3.63
3220:PLBELCELCLPR	OTDF	CE	4.55	4.68	4.55	4.39	4.04	
3221:PLRELCELCLPB	OTDF	CE	5.42	5.48	5.31	5.21	4.78	
3225:MUNBURDUMWIL	OTDF	CE/NIPS	3.54	3.56	3.43	3.31	3.25	
3230:GDBLPBGDRLPR	OTDF	CE	7.49	7.42	7.27	7.18	6.62	4.11
3258:QUARCKQUADAV	OTDF	ALTW/CE			4.55			
3707:LORTRKWEMPAD	OTDF	ALTW	3.41			3.35	3.02	
3715:QUARCKCORMOL	OTDF	ALTW/CE			4.82			
4051:WEMPADEA__CE	OTDF	CE/ATC	8.80	7.31	8.11	8.28	8.08	7.49
4052:ZIOPLPWP__CE	OTDF	CE/ATC	34.72	32.13	32.92	33.28	30.89	25.59
4068:AEP-MECS	PDTF	AEP/MECS						8.83
4116:COOBENCOOPAL	OTDF	AEP						3.80
4118:PALBENTWBARG	OTDF	AEP/MECS	3.88	3.90	3.86	3.82	3.57	
4119:COOPALCOOBEN	OTDF	AEP/MECS						3.78
4120:PALCOOTWBARG	OTDF	AEP/MECS	3.30	3.32	3.29	3.25	3.04	
4177:COOPALBENPAL	OTDF	AEP/MECS						4.38
4187:LORTRKWPAD_G	OTDF	ALTW	3.76			3.68	3.32	
4188:TRKCSVWPAD_G	OTDF	ALTW/DPC	4.04	3.14		3.87	3.60	3.23
5050:STJLAKIATSTR	PDTF	KCPL/MPS						4.14
6004:MWSI	PDTF	NSP/ATC	12.48	12.29	12.26	12.95	10.15	10.74
6009:COOPER_S	PDTF	OPPD/NPPD						4.33
9903:EAU_ARP_XCEL	PDTF	NSP/ATC	12.07	11.72	11.50	10.51	9.36	9.38
9905:TRKCASWEMPAD	OTDF	ALTW/DPC	3.69			3.53	3.28	
63007:COLXFMCOLPLO	OTDF	CE	3.39	3.45	3.34	3.21	3.08	
63019:LCOBYRELCNEL	OTDF	CE	13.66	15.51	10.94	11.94	12.17	12.68
63020:LEEBYNEAUARP	OTDF	CE	14.77	17.04	12.09	12.51	12.95	12.65
63026:LBRIADPRLBR	OTDF	CE	8.26	8.01	7.84	7.85	7.30	5.25
63034:LOMD46ITALOM	OTDF	CE	8.35	8.10	7.93	7.94	7.38	5.30
63035:EFRGOOWILDUM	OTDF	CE	5.17	5.16	5.06	4.97	4.60	
63038:GDRLPRKENCLR	OTDF	CE	7.18	7.11	6.94	6.86	6.34	4.21
63039:GDBLPBJOBLPB	OTDF	CE	6.35	6.29	6.17	6.09	5.61	3.43
63040:LOBITBDPBLOB	OTDF	CE	8.17	7.80	7.70	7.75	7.22	5.37
63081:DUMWILJEFROC	OTDF	AEP/CE	7.44	7.50	7.23	6.96	6.84	
63082:DUMWILUPNEFR	OTDF	AEP/CE	9.76	9.81	9.51	9.22	8.85	
63084:MUNBRNWILDUM	OTDF	CE/NIPS	3.61	3.63	3.50	3.37	3.32	
63086:CREEFRWILDUM	OTDF	CE	5.55	5.57	5.44	5.31	4.96	
63103:GOOGOODREELC	OTDF	CE	5.66	5.62	5.52	5.46	4.96	3.89
63117:CORNEL471NEL	OTDF	CE	5.76	6.78		3.94	5.44	5.98
63118:471NELCORNEL	OTDF	CE	5.78	6.81		3.95	5.46	6.00

Notes:

OTDF: Contingent flowgate; PDTF: Non-contingent flowgate

Combined Project Network Analysis

ATC also analyzed the relative performance of constructing two of the representative proxy projects. The results of this analysis are shown graphically in Figure VI-4 and in Table VI-4. Figure VI-4 provides a comparison of the improved import capability versus the project costs for each of the combined projects. Table VI-4, below, summarizes this information.

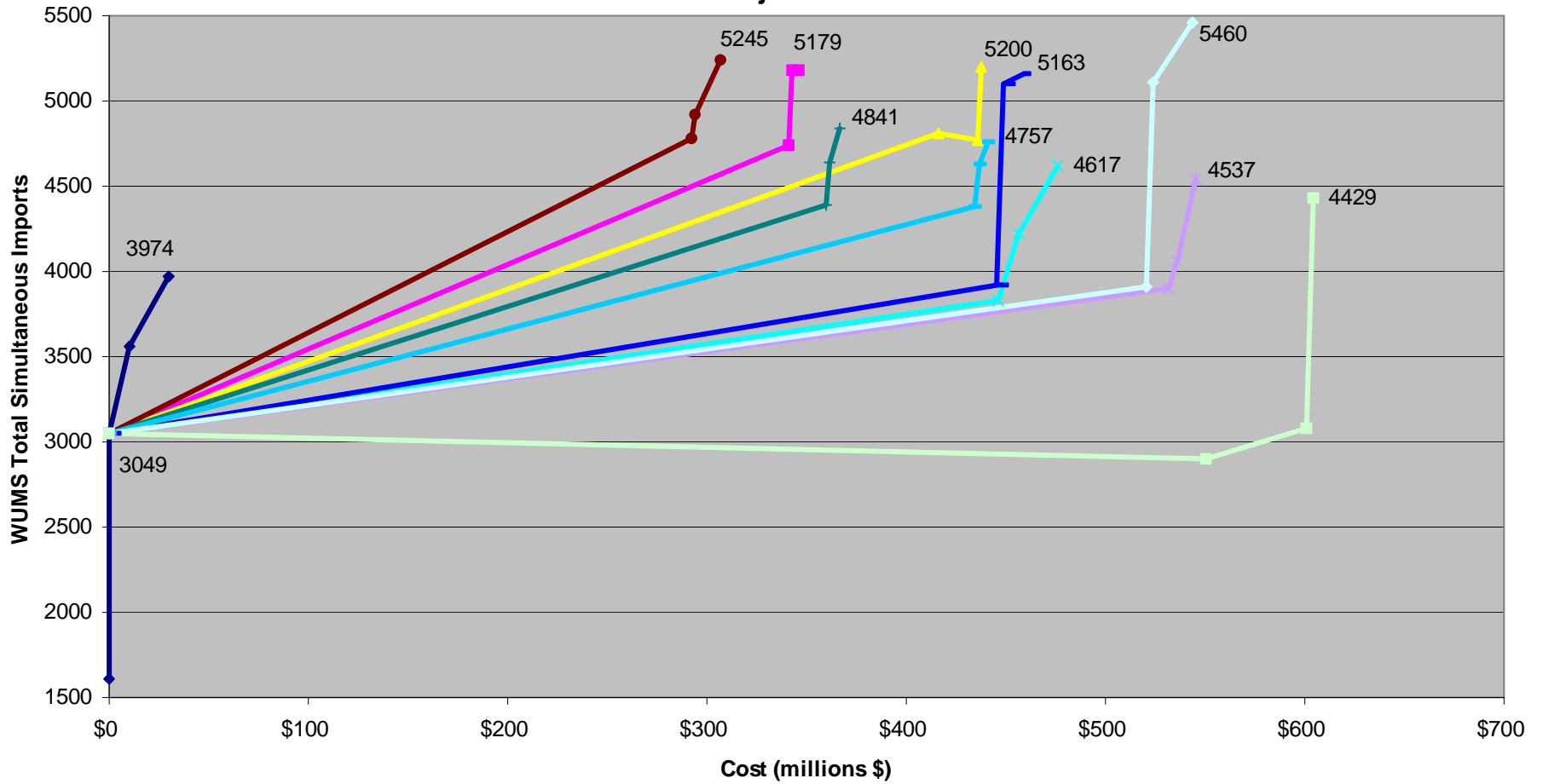
Conclusions – Directional Analysis

- ❑ Achievable import capability gains are very dependent on direction.
- ❑ Representative projects to the south and southwest, individually, appear to provide the largest increases in import capability.
- ❑ Based on the screening-level capital cost estimates, the representative project to the south appears to provide the best value in terms of increasing import capability.
- ❑ If two of the representative projects were constructed, representative projects to the southwest and east appear to provide the largest increase in import capability.
- ❑ Based on capital cost estimates, the representative projects to the south and southwest appear to provide the best value in terms of increasing import capability.
- ❑ Additional analyses will need to be done to confirm these conclusions, and to more fully flesh out the economic impact picture.

**Table VI-4
Costs and Import Capability from Combined Project Analysis**

Project	Total Cost (Millions)	Total WUMS Simultaneous Import Capability (megawatts)
Base Case – No major project	\$30	3,974
Adams-Columbia and Byron-N. Madison	\$346	5,179
Adams-Columbia and Salem-N. Madison	\$438	5,200
Adams-Columbia and Sault Ste. Marie-Arnold	\$476	4,617
Adams-Columbia and Ludington-Forest Junction	\$546	4,537
Byron-N. Madison and Salem-West Middleton	\$307	5,245
Byron-N. Madison and Sault Ste. Marie-Arnold	\$367	4,841
Byron-N. Madison and Ludington - Forest Junction	\$459	5,163
Salem-N. Madison and Sault Ste. Marie-Arnold	\$441	4,757
Salem-N. Madison and Ludington-Forest Junction	\$544	5,460
Sault Ste. Marie-Arnold and Ludington-Forest Junction	\$604	4,429

**Figure VI-4
Comparison of Combined Major Alternatives
Access Project - Phase I**



- ◆ Base Case - No Major Project
- ▲ Adams - Columbia & Salem - North Madison
- ✱ Adams - Columbia & Ludington - Forest Junction
- ◆ Byron - North Madison & Sault Ste. Marie - Arnold
- ◆ Salem - North Madison & Sault Ste. Marie - Arnold
- ◆ Sault Ste. Marie - Arnold & Ludington - Forest Junction
- ◆ Adams - Columbia & Byron - North Madison
- ◆ Adams - Columbia & Sault Ste. Marie - Arnold
- ◆ Byron - North Madison & Salem - West Middleton
- ◆ Byron - North Madison & Ludington - Forest Junction
- ◆ Salem - North Madison & Ludington - Forest Junction

Appendix A

Transmission-Distribution Interconnections - Updated

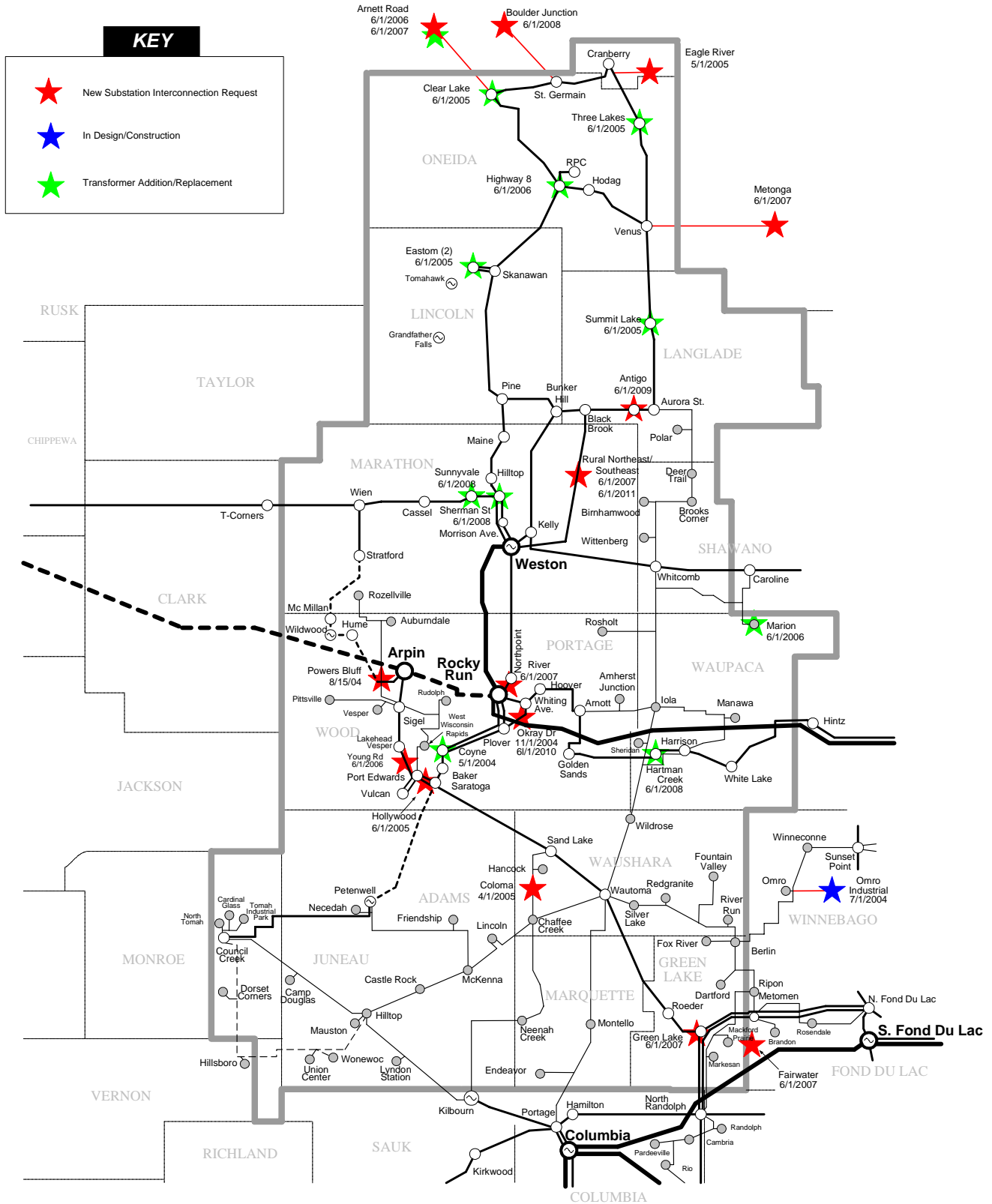
ATC has received numerous requests from distribution companies for new T-D interconnections. These interconnections generally take on three different types of projects:

1. Constructing new T-D substations. Typically, these new interconnections involve constructing a new T-D substation adjacent to an existing transmission line and looping the transmission line into the new substation. In some instances, the new substation cannot be sited adjacent to the transmission line and ATC is required to construct a transmission line to the new substation site. Since this type of interconnection is a way for a distribution company to redistribute load between the two existing substations, it typically does not materially affect transmission system performance. In some instances, however, the optimum site for the new substation, from a distribution planning perspective, is such that a new transmission line from two substations that were not previously interconnected is warranted, forming a new network line, which can materially affect transmission system performance.
2. Adding T-D transformers at existing substations. These new interconnections involve expanding an existing T-D substation to accommodate a new T-D transformer. Typically, this type of interconnection is a way for a distribution company to improve reliability by providing redundancy, lower the loading on existing T-D transformers and meet increasing customer demand.
3. Replacing existing T-D transformers at existing substations. These are not technically new interconnections since no expansion is required at the existing T-D substation – it's merely a means of increasing transformer capacity. This type of project is a way to reliably serve increasing customer demand.

In some instances, the reason for a new T-D interconnection request is driven by a large new customer load, such as a new industry with a large demand for electricity. In these instances, there may be a need for other transmission system reinforcements to reliably serve the new load.

All of the T-D interconnection requests that are being implemented, designed or evaluated by ATC are shown in Figures A-1 through A-5 for Zones 1-5, respectively. A corresponding list of these interconnection requests is available on ATC's web site [American Transmission Company ~ The Energy Access Company](http://www.atc.com)~ at www.atc.com.

Figure A-1 Transmission-Distribution Interconnection Requests - Zone 1



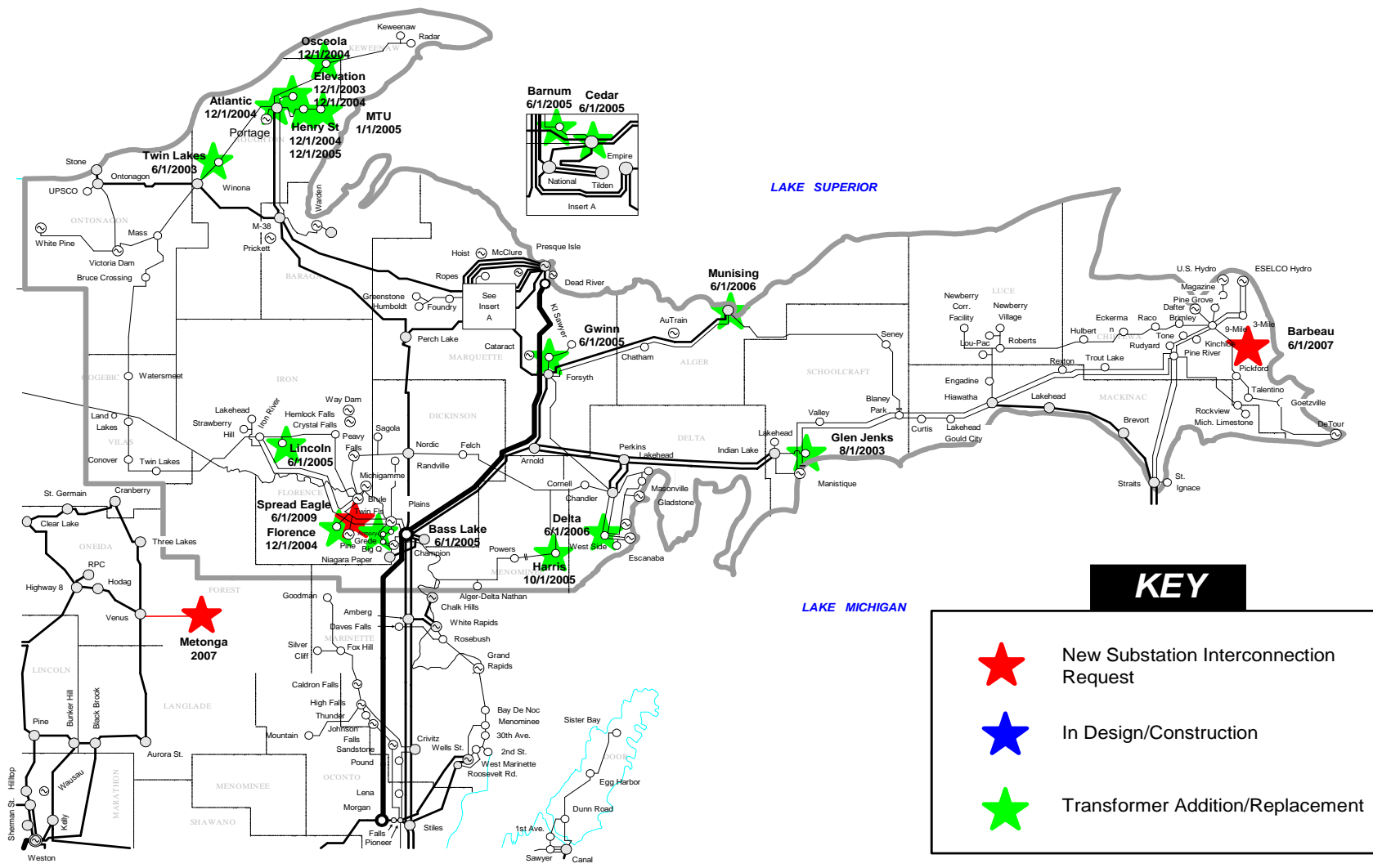


Figure A-2
Transmission-Distribution Interconnection Requests - Zone 2

Figure A-3 Transmission-Distribution Interconnection Requests - Zone 3

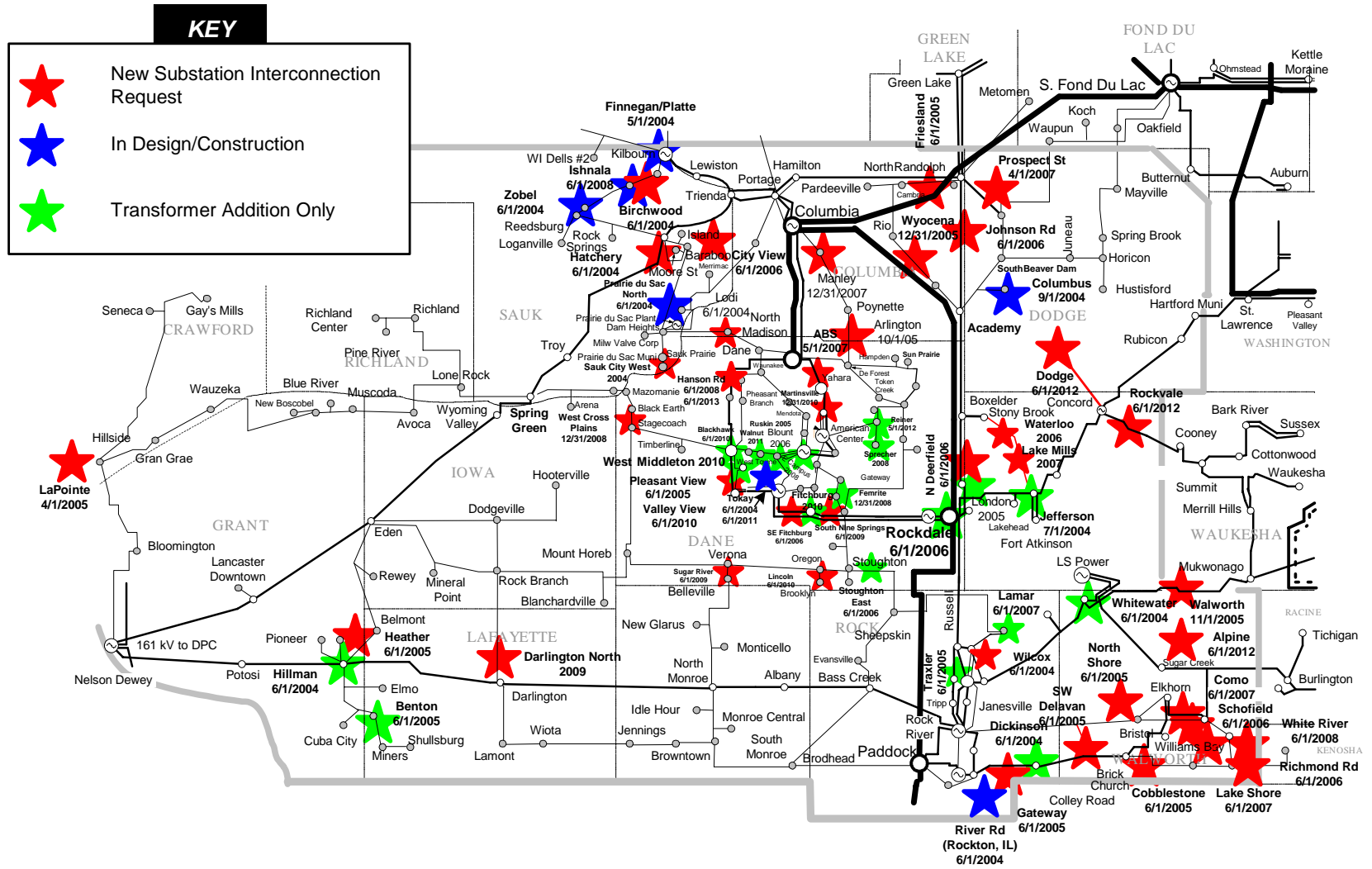
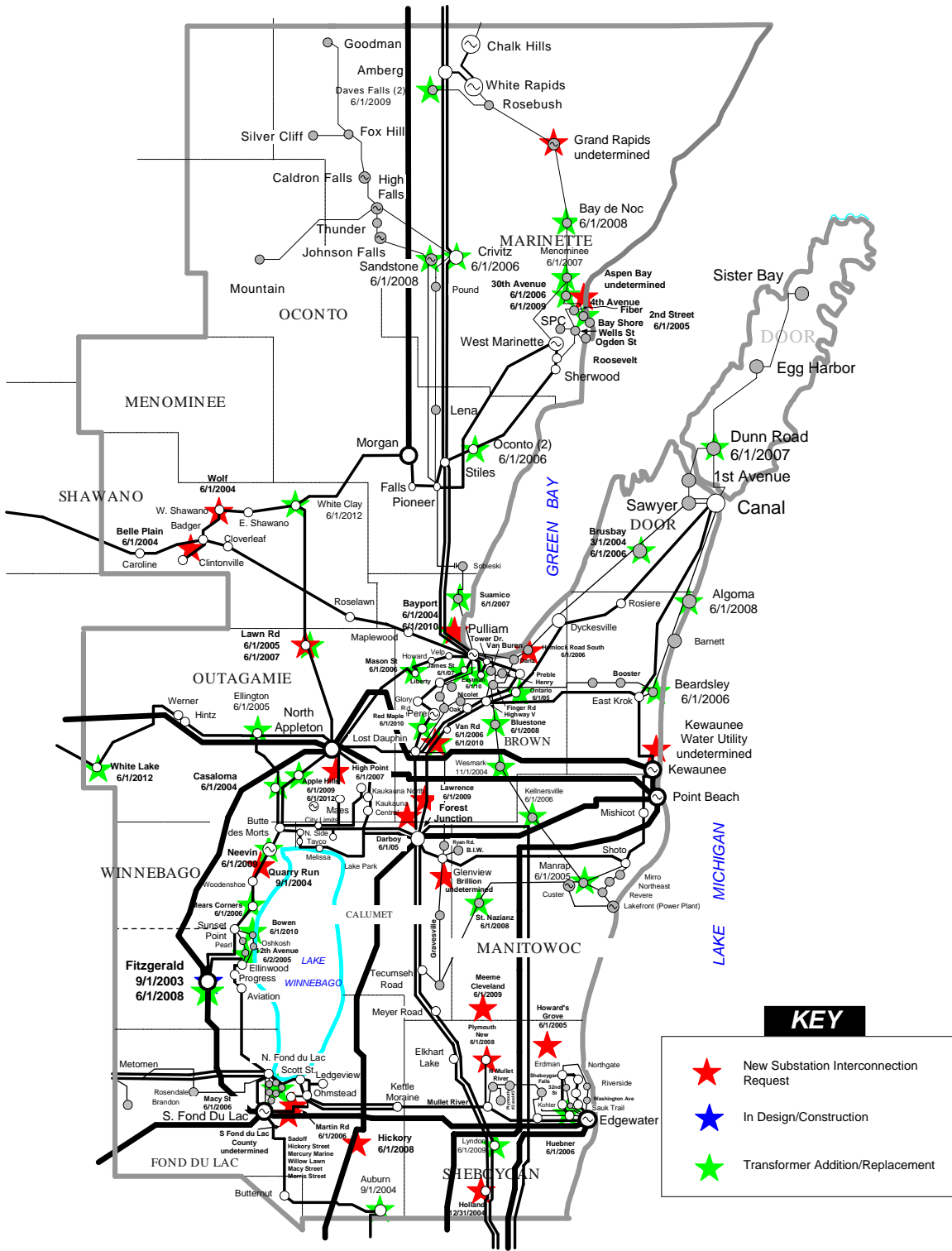
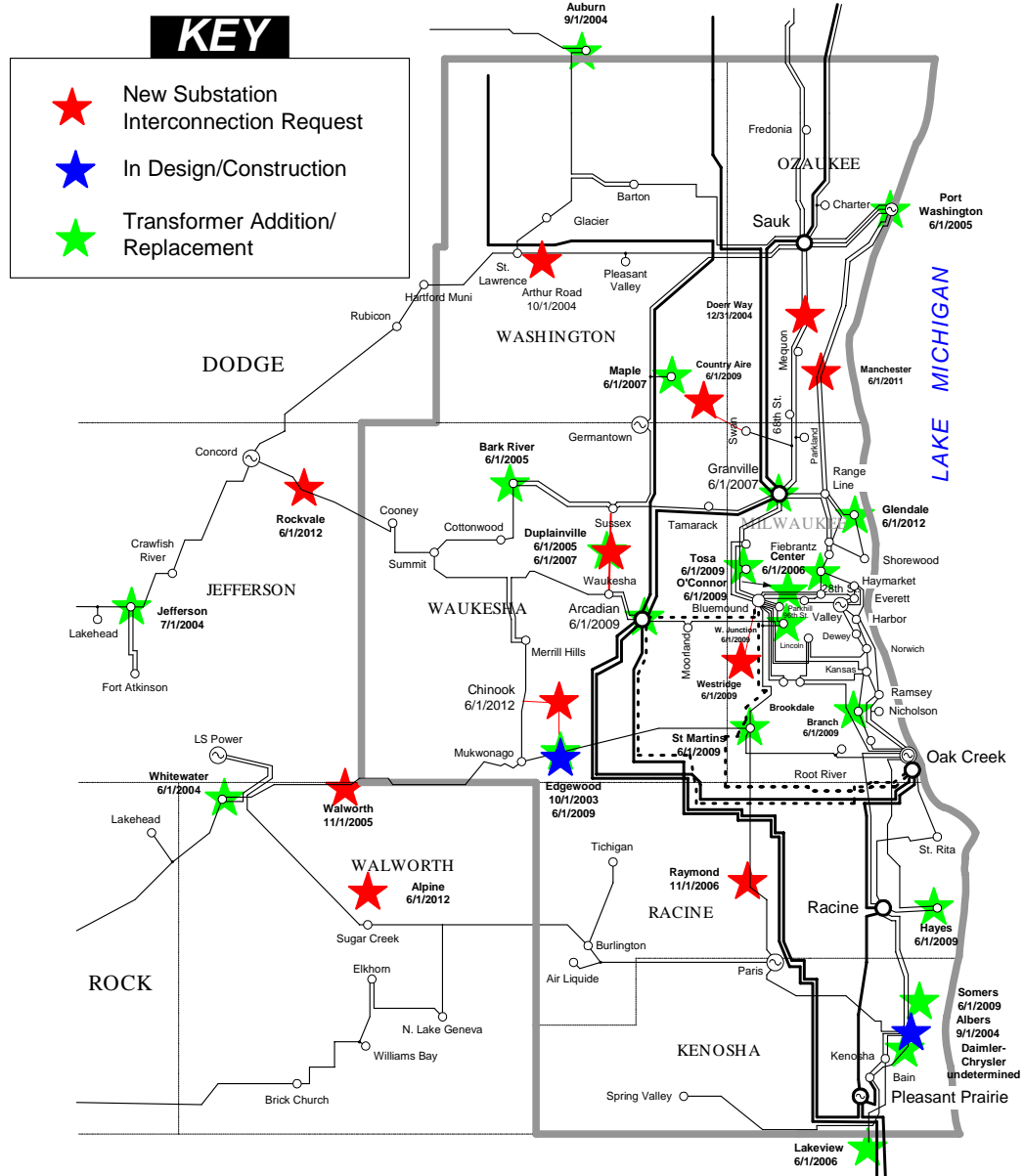


Figure A-4
Transmission-Distribution Interconnection Requests - Zone 4



**Figure A-5
Transmission-Distribution Interconnection Requests - Zone 5**



Appendix B

Summary of Changes to the 2003 10-Year Assessment

For the below tables, the following color-coding scheme was utilized for indicating what type of change has been made to the 10-Year Assessment from 2003 to the 2003 Update (pages 90-95 of this document). Projects that have been removed from the 2003 10-Year Assessment can be found on pages 96 and 97 of this document.

Color	Reason for Change to the 2003 TYA Update
Gray	in-service year
Light Blue	new to the 10-Year Assessment
White	other change in scope

Changes to the 2003 10-Year Assessment Update include the following major and minor projects:

Major Project: Plains-Stiles 138 kV Double-Circuit Rebuild

Associated Major Project	Planned Additions	Previous In-Service Year (if applicable)	Projected In-Service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Plains-Stiles	Rebuild existing West Marinette-Menominee 69 kV line to double circuit 138/69 kV	N/A	2005	2	reliability, service limitation	Planned	\$ 6.9
Plains-Stiles	Convert Menominee-Rosebush 69 kV line to 138 kV	N/A	2005	2	reliability, service limitation	Planned	\$ 11.4
Plains-Stiles	Rebuild/reconductor Rosebush-Amberg 138 kV line	N/A	2005	2	reliability, service limitation	Planned	\$ 6.8

Major Project: Arrowhead-Weston 345 kV line

Associated Major Project	Planned Additions	Reason for Change (if applicable)	Projected In-Service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Arrowhead-Weston	Construct new Gardner Park 345/115 kV substation	Weston renamed Gardner Park	2006	1	service limitation, reliability, import capability & Weston stability	Proposed	included in A-W estimate
Arrowhead-Weston	Replace 345/115 kV 200 MVA transformer at Weston with two 500 MVA units at the Gardner Park substation	Weston renamed Gardner Park	2006	1	service limitation, reliability, import capability & Weston stability	Planned	included in A-W estimate
Arrowhead-Weston	Construct Gardner Park-Stone Lake 345 kV line	Weston renamed Gardner Park	2006	1	service limitation, reliability, import capability & Weston stability	Planned	\$ 262.1
Arrowhead-Weston	Install a 345/161 kV transformer at Stone Lake (temporary installation for construction outages)	N/A	2006	1	reliability	Proposed	included in A-W estimate
Arrowhead-Weston	Install 1-40 MVAR capacitor banks at Arpin 138 kV	N/A	2008	1	achieve transfer capability associated with Arrowhead-Weston	Proposed	included in A-W estimate
Arrowhead-Weston	Install 6-34 MVAR capacitor banks at Gardner Park 115 kV	N/A	2008	1	achieve transfer capability associated with Arrowhead-Weston	Proposed	included in A-W estimate
Arrowhead-Weston	Install 4-50 MVAR capacitor bank at Arrowhead 230 kV	N/A	2008	1	achieve transfer capability associated with Arrowhead-Weston	Proposed	included in A-W estimate

Major Project: Elm Road Generation

Associated Major Project	Planned Additions	Previous In-Service Year	Projected In-Service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Elm Road generation	Expand Oak Creek 345 kV switchyard to interconnect one new generator	2007	2009	5	new generation	Proposed	\$ 18.8
Elm Road generation	Construct an Oak Creek-Brookdale 345 kV line installing 4 mi. new structures, converting 16.2 mi. of non-operative 230 kV and 5 mi. 138 kV	2007	2010	5	new generation	Proposed	\$ 17.3
Elm Road generation	Construct a Brookdale-Granville 345 kV line converting/reconductoring 5.6 mi. 138 kV, rebuilding 7 mi. 138 kV double circuit tower line and converting/reconductoring 3 mi. 138 kV on existing 345 kV structures	2007	2010	5	new generation	Proposed	\$ 19.3
Elm Road generation	Construct a 345/138 kV switchyard at Brookdale to accommodate two 345 kV lines, a 500 MVA 345/138 kV transformer and 4-138 kV lines plus two 138-26.2 kV transformers	2007	2010	5	new generation	Proposed	\$ 14.8
Elm Road generation	Convert and reconductor Oak Creek-Bluemound 230 kV line K862 to 345 kV and loop into Arcadian 345 kV substation	2011	2012	5	new generation	Proposed	\$ 34.8
Elm Road generation	Construct Oak Creek-Racine 345 kV line with 4 mi new structures and conductor, plus convert 9.6 mi. 138 kV line KK812 to 345 kV	2011	2012	5	new generation	Proposed	\$ 8.1
Elm Road generation	Expand Oak Creek 345 kV switchyard to interconnect three new generators	2011	2012	5	new generation	Proposed	\$ 21.5
Elm Road generation	Associated other 138 or 345 kV facilities	2007-2011	2009-2012	5	new generation	Proposed	\$ 55.9

Other Major Projects

Associated Major Project	Planned Additions	Previous In-Service Year or Reason for Change (if applicable)	Projected In-Service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Fox Energy	Construct a Fox Energy-Forest Junction 345 kV line	N/A	2005	4	new generation	Planned	\$ 4.5
Fox Energy	Construct new Fox Energy 345 kV switchyard	N/A	2005	4	new generation	Planned	\$ 7.1
	Construct a Jefferson-Lake Mills-Stony Brook 138 kV line	2006	2007	3	reliability, T-D interconnection	Proposed	\$ 11.3
Rockdale-Lannon Junction	Construct a new Lannon Junction substation at intersection of Granville-Arcadian 345 kV, Sussex-Tamarack 138 kV and Sussex-Germantown 138 kV lines; install a 345/138 kV, 500 MVA transformer	No longer looping in Forest Junction-Arcadian 345 kV line	2007	5	reliability & Germantown generation stability	Proposed	\$ 14.2
Weston 4 generation	Construct new Central Wisconsin 345 kV substation	N/A	2009	1 & 4	service limitation, reliability, import capability & Weston stability	Proposed	\$ 10.5
Weston 4 generation	Construct Gardner Park-Central Wisconsin 345 kV line	N/A	2009	1	service limitation, reliability, import capability & Weston stability	Proposed	\$ 86.6
Morgan-Werner West	String a new 138 kV line from Clintonville-Werner West primarily on Morgan-Werner West 345 kV line structures	N/A	2009	4	reliability, service limitation	Proposed	included in Morgan-Werner estimate
	Construct 345 kV line from Paddock to new Sugar River 345 kV switchyard; loop Kegonsa-West Middleton 345 kV line into Sugar River	Verona was renamed Sugar River	2012	3	reliability, transfer capability	Provisional	\$ 119.3

Minor Projects

Planned Additions	Previous In-Service Year or Reason for Change (if applicable)	Projected In-Service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Rebuild from Nordic to Randville SS (5 miles) of single circuit 69 kV line to double circuit 69 kV	2005	2004	2	reliability, condition	Planned	\$ 1.6
Construct a tap to Belle Plain from the Badger-Caroline 115 kV line	N/A	2004	4	T-D interconnection	Planned	\$ 1.1
Uprate Rocky Run-Northpoint 115 kV line terminal equipment at Northpoint	N/A	2005	1	reliability, new generation	Planned	\$ 0.06
Install 26 MVAR capacitor bank at Hartford	N/A	2005	5	reliability	Proposed	\$ 1.0
Install 69 kV phase shifter or fixed reactor at Council Creek	2004	2006	1	reliability	Proposed	\$ 1.9
Construct double circuit 138 kV line from Forest Junction/Charter Steel to Howards Grove	Was Erdman-Howards Grove	2006	4	T-D interconnection	Planned	\$ 8.2
Replace the two existing 33 MVA 138/69 kV transformers at Edgewater with two 60 MVA transformers	N/A	2006	4	reliability	Proposed	\$ 2.4
Replace the existing 46.7 MVA 138/69 kV transformer at South Sheboygan Falls with 100 MVA transformer	N/A	2006	4	reliability	Proposed	\$ 1.3
Replace the existing 46.7 MVA 138/69 kV transformer at Mullet River with 100 MVA transformer	N/A	2006	4	reliability	Proposed	\$ 1.3
Construct a Martin Road-South Fond du Lac/Ohmstead 138 kV line	N/A	2006	4	T-D interconnection	Planned	\$ 1.6
Construct an Eagle River-Cranberry/Three Lakes 115 kV line	2005	2007	1	T-D interconnection	Proposed	\$ 0.3
Construct Venus-Metonga 115 kV line	2005	2007	1	T-D interconnections	Proposed	\$ 5.0
Uprate Rockdale to Boxelder 138 kV line	2005	2007	3	reliability	Proposed	\$ 0.3

Minor Projects (continued)

Planned Additions	Previous In-Service Year or Reason for Change (if applicable)	Projected In-Service Year	Planning Zone	Need Category	Planned, Proposed or Provisional	Capital Cost Estimate (Millions)
Construct new 69 kV line from Brooklyn to Sugar River Substation	Was Brooklyn to Belleville	2007	3	reliability	Proposed	\$ 5.0
Construct Clear Lake-Arnett Road 115 kV line	2006	2008	1	T-D interconnection	Proposed	\$ 2.1
Construct a Rubicon-Hustisford 138 kV line	N/A	2008	3	reliability	Provisional	\$ 4.8
Rebuild Hustisford-Horicon 69 kV to 138 kV	N/A	2008	3	reliability	Provisional	\$ 2.7
Construct 138/69 kV substation at a site near Horicon and install a 138/69 kV transformer	N/A	2008	3	reliability	Provisional	\$ 2.8
Construct new 138 kV bus and 138/69 kV 100 MVA transformer at Sugar River Substation	Verona was renamed Sugar River	2009	3	reliability	Provisional	\$ 1.4
Construct new 138 kV line from Sugar River to Southeast Fitchburg Substation	Verona was renamed Sugar River	2009	3	reliability	Provisional	\$ 5.1

Projects Removed from the 2003 10-Year Assessment

Formerly Planned Additions	Projected In-Service Year	Planning Zone	Reason for Removal
Replace 400 A CT at S Fond du Lac 69 kV	2003	4	revised load/model information
Replace 600 A CT at N Fond du Lac 138 kV	2005	4	revised load/model information
Construct 2.5 miles of 138 kV line from Lodestar to Sheboygan Falls	2006	4	another alternative selected
Install a 138/69 kV, 60 MVA transformer at Sheboygan Falls	2006	4	another alternative selected
Install 10 MVAR capacitor bank at Jefferson 138 kV	2007	3	another alternative selected
Install 2-13 MVAR capacitor banks at Concord 138 kV	2007	3	another alternative selected
Construct a second Germantown-Lannon 138 kV line	2007	5	revised study results
Convert and reconductor Oak Creek-Bluemound 230 kV line K873 to 345 kV	2007	5	generation restudy results
Reconnect Oak Creek unit #7 to 345 kV switchyard	2007	5	generation restudy results
Expand 345 kV switchyard at Bluemound to accommodate three additional 345 kV lines and two additional 500 MVA 345/138 kV transformers	2011	5	generation restudy results
Reconnect Oak Creek unit #8 to 345 kV switchyard	2011	5	generation restudy results
Reroute Brookdale-Granville 345 kV line into expanded Bluemound 345 kV switchyard	2011	5	generation restudy results
Rebuild/convert South Fond du Lac-Springbrook 69 kV to 138 kV	2008	3	another alternative selected
Construct 138 kV bus and install a 138/69 kV transformer at Springbrook	2008	3	another alternative selected

Projects Removed from the 2003 10-Year Assessment (continued)

Formerly Planned Additions	Projected In-Service Year	Planning Zone	Reason for Removal
Construct 345 kV switchyard at Weston	2006	1	renamed Gardner Park
Install 2-25 MVAR capacitor banks at Arpin 115 kV	2008	1	another alternative selected
Install 2-40 MVAR capacitor banks at Weston 115 kV	2008	1	another alternative selected
Install 3-52 MVAR capacitor banks at Rocky Run 115 kV	2008	1	another alternative selected
Install second 345/115 kV 500 MVA transformer at Weston	2008	1	another alternative selected
Construct 138 kV line from Metonga to new Laona and operate at 115 kV	2006	1	canceled by customer
Construct South Beaver Dam-North Beaver Dam 138 kV line	2007	3	another alternative selected
Convert Academy-South Beaver Dam 69 kV line to 138 kV	2007	3	another alternative selected

