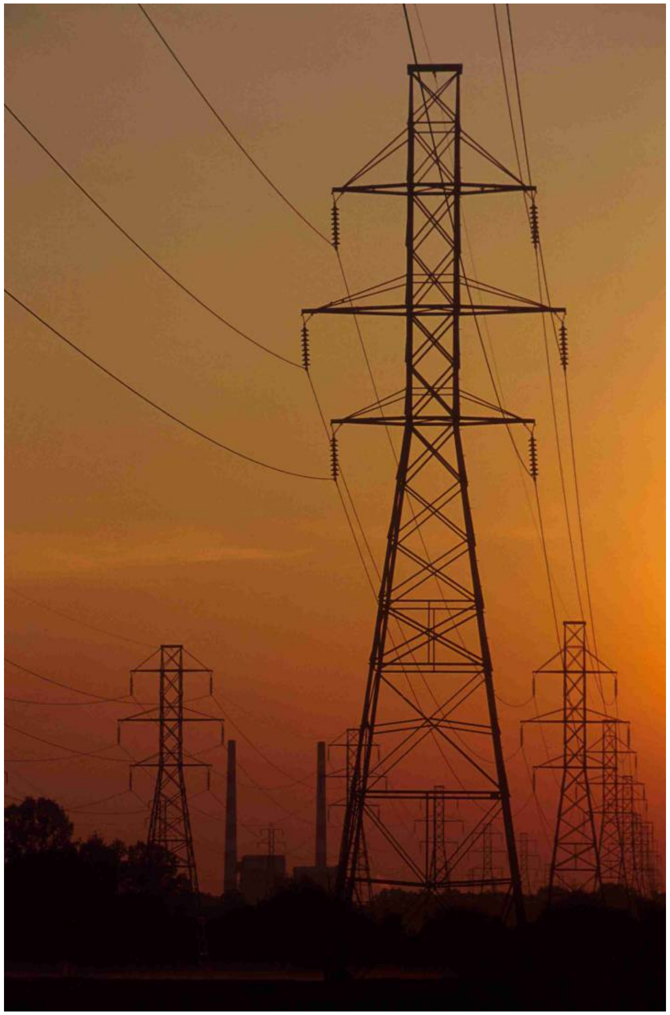
ITC Presentation to Wind Energy Resource Zones Board

January 5, 2009

Agenda

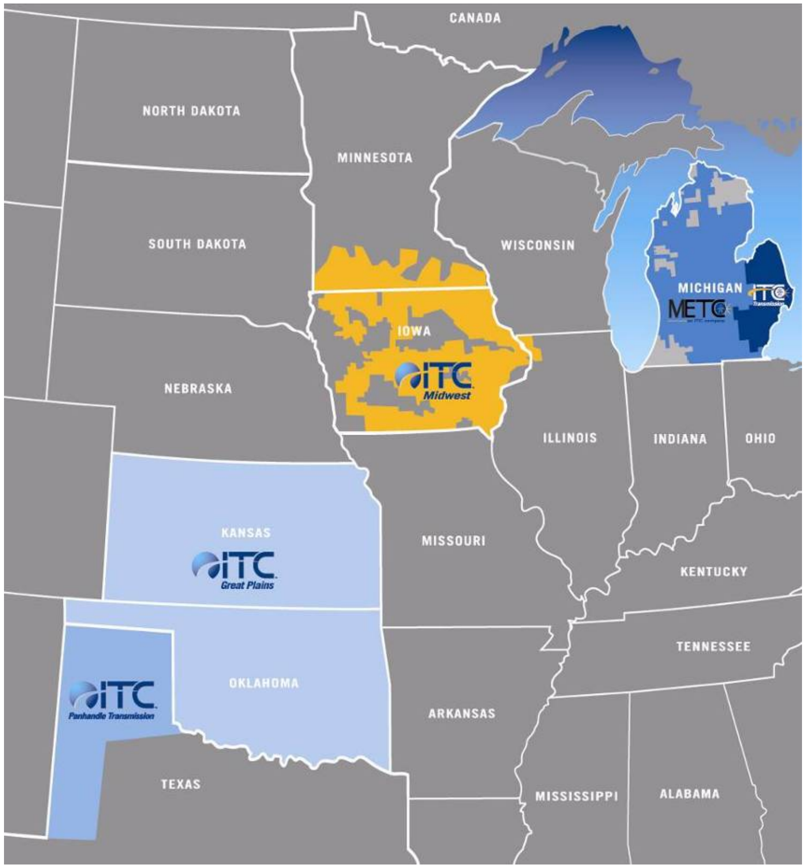
- Who is ITC?
- Organizations
- Transmission Planning 101
- Planning Process

Who is ITC?



- The first and largest fully independent transmission company in the U.S.
- The eighth largest transmission-owning company in the U.S.
- Current Footprint:
  - Michigan
  - Iowa
  - Minnesota
  - Illinois
  - Missouri
  - Kansas (utility status)
  - Oklahoma (utility status)

Who Is ITC?



- March 2003: ITC established when DTE Energy sold transmission subsidiary ITC*Transmission*
- July 2005: ITC listed on the New York Stock Exchange
- October 2006: ITC acquired Michigan Electric Transmission Company, LLC (METC)
- December 2007: ITC Midwest expanded into Iowa with acquisition of Interstate Power & Light Company (IP&L) transmission assets
- Today: Actively seeking opportunities to build, own, operate and maintain transmission in Kansas, Oklahoma and Texas
- Rate regulation by the Federal Energy Regulatory Commission (FERC)

ITC Business Model

- ITC is not an energy market participant
  - Does not buy or sell energy
  - Does not participate in the congestion management systems
- Focus on planning, construction, operation, and maintenance of transmission facilities

ITC System Statistics

Subsidiary	ITC*Transmission*	METC	ITC Midwest
System Peak Load	12,745 MW	9,469 MW	3,100+ MW
Service Area	Southeastern Michigan	Lower Peninsula of Michigan	Portions of Iowa, Minnesota, Illinois and Missouri
Total Transmission Miles	More than 2,700	Approximately 5,400	Approximately 6,800
Membership	Midwest ISO	Midwest ISO	Midwest ISO
ITC Acquired Transmission Assets	March 1, 2003	October 10, 2006	December 20, 2007

Organizations

- Federal Energy Regulatory Commission (FERC)
  - Regulates transmission/sets rates
  - Gives NERC authority to assess financial fines for non-compliance with standards
- Michigan Public Service Commission (MPSC)
  - Active stakeholder
  - Siting authority – mandatory for lines >5 miles *and* at least 345kV
- North American Electric Reliability Council (NERC)
  - Sets reliability standards

Organizations

- Reliability*First* Corporation (RFC)
  - Enforces reliability standards
  - Regional reliability organization
- Midwest Independent Transmission System Operator (Midwest ISO)
  - Regional operator
  - Produces Midwest ISO Transmission Expansion Plan (MTEP) in planning oversight role
  - Generation interconnection queue
  - Operates energy market
  - Will soon operate ancillary services market

NERC Reliability Standards

- NERC reliability standards define the reliability requirements for planning and operating the North American bulk power system. TPL 001-004 governs transmission Planning. ITC Planning Criteria adds specificity.

Standard TPL-002-0 — System Performance Following Loss of a Single BES Element

Table I. Transmission System Standards — Normal and Emergency Conditions

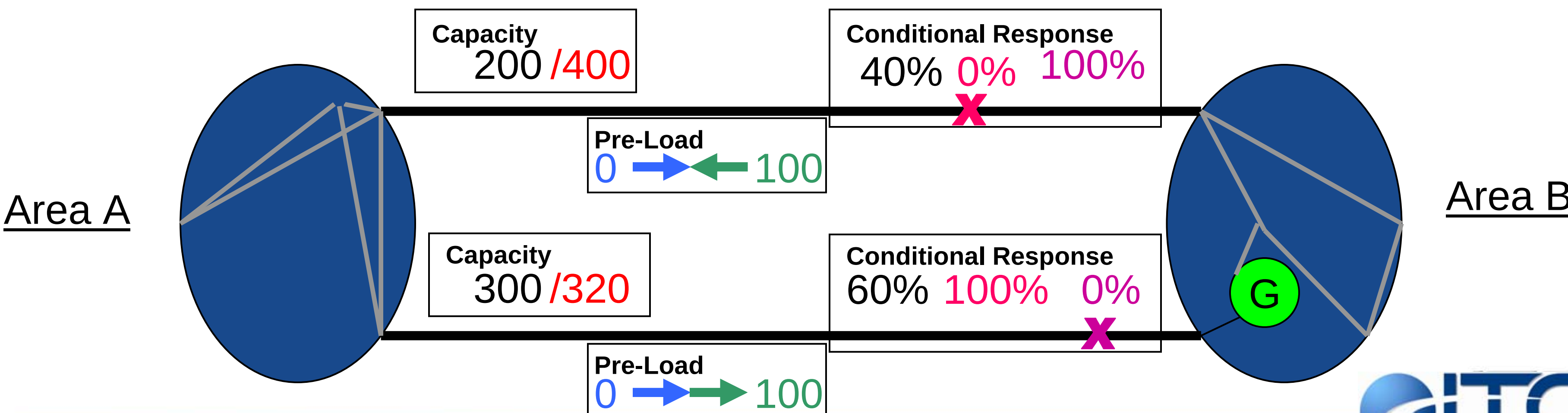
Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No

NERC Reliability Standards (cont.)

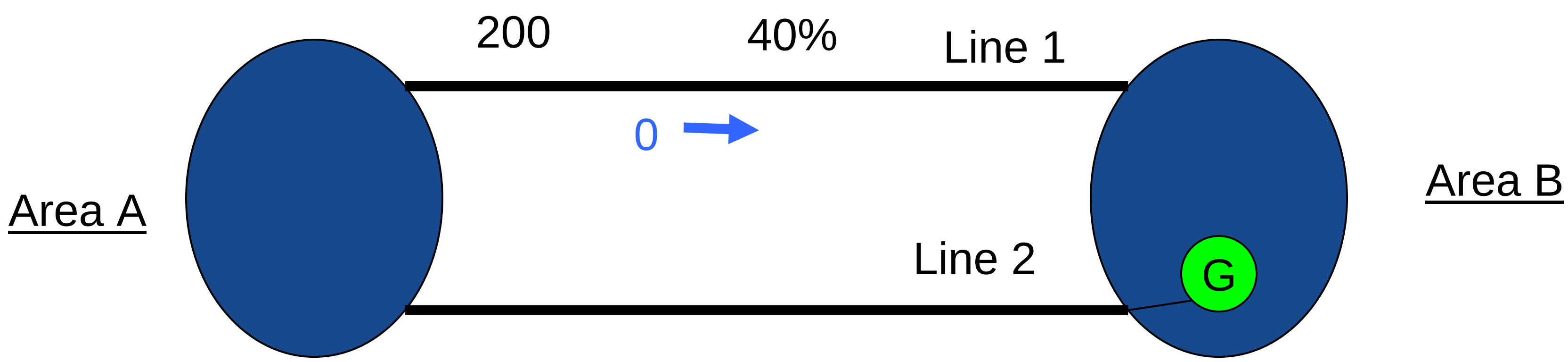
Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

Planning 101 – How Much Can Be Moved Across the System - Factors

- *Topology:* How many facilities are there and how are they connected?
- *Capacity:* What are these facilities capable of carrying?
  - "Normal" – an applicable rating that sets the amount of flow that can be carried for an indefinite period of time
  - "Emergency" – an applicable rating that sets the amount of flow that can be carried for a shorter, defined period of time
- *Response:* How does the power flow split up amongst the facilities (related to topology)
  - "Normal" – all facilities in service
  - "Post-Contingency" – after facility or facilities is/are suddenly outaged, many different contingencies considered
- *Pre-load:* How much is flow on the lines before transfers?
  - Generator dispatch 1 (with Generator G on line)
  - Generator dispatch 2 (with Generator G off line)



Determination of System Capability – Simplified Example



- For power moving from A to B (transfer) impact on Line 1 with Generator (G) on line and all transmission in-service
  - 200 MWs rating + 0 MWs pre-existing flow = 200 MWs of capacity available
  - A to B transfers * 40% = 200

➔***A to B transfers limited to 500 MWs for this condition***

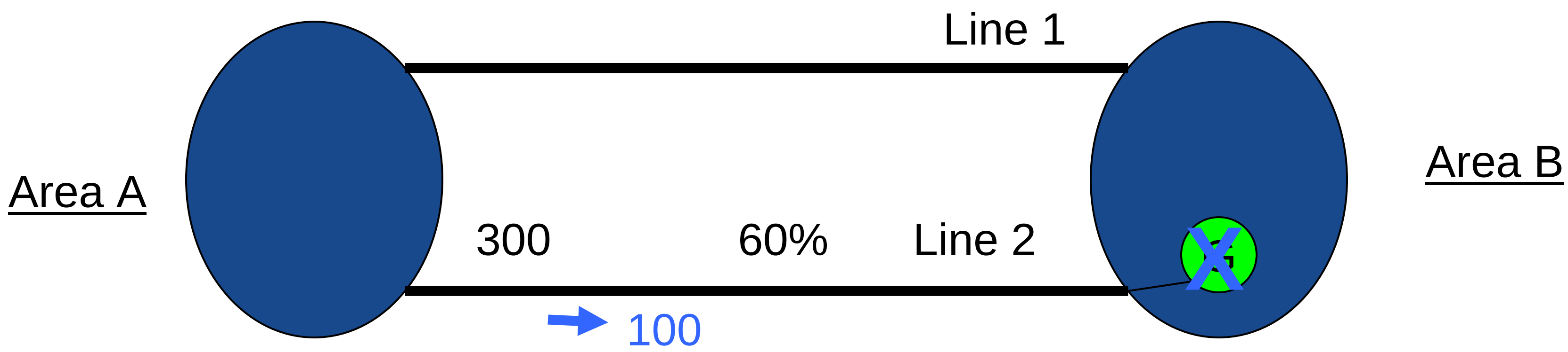
Check -- Flow through Line 1 After Transfer

pre-existing flow + percentage of transfer * transfer = Rating of Line 1

0 + 40% * 500 = 200

➔A to B transfers limit confirmed for this condition

Determination of System Capability – Simplified Example (cont.)



- For power moving from A to B impact on Line 2 with Generator (G) off line and all transmission in-service
  - 300 MWs rating - 100 MWs pre-existing flow = 200 MWs of capacity available
  - A to B transfers * 60% = 200

➔***A to B transfers limited to 333 MWs for this condition***

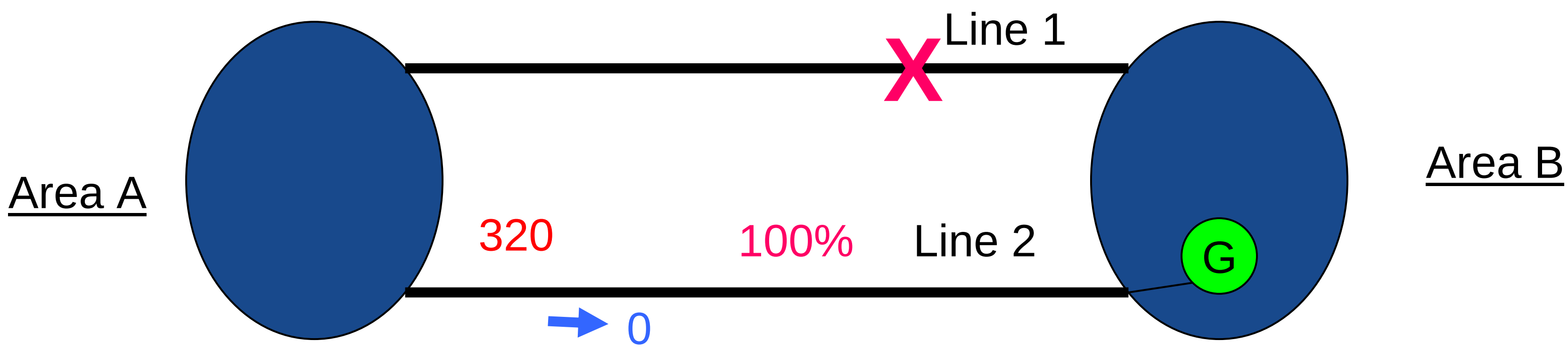
Check -- Flow through Line 2 After Transfer

pre-existing flow + percentage of transfer * transfer = Rating of Line 2

100 + 60% * 333 = 300

➔A to B transfers limit confirmed for this condition

Determination of System Capability – Simplified Example (cont.)



- For A to B transfers – Line 2 with Line 1 out
  - 320 MWs rating - 0 MWs pre-existing flow = 320 MWs of capacity available
  - A to B transfers * 100% = 320

➔***A to B transfers limited to 320 MWs for this condition***

Check -- Flow through Line 2 with Line 1 out After Transfer

pre-existing flow + percentage of transfer * transfer = = Rating of Line 2

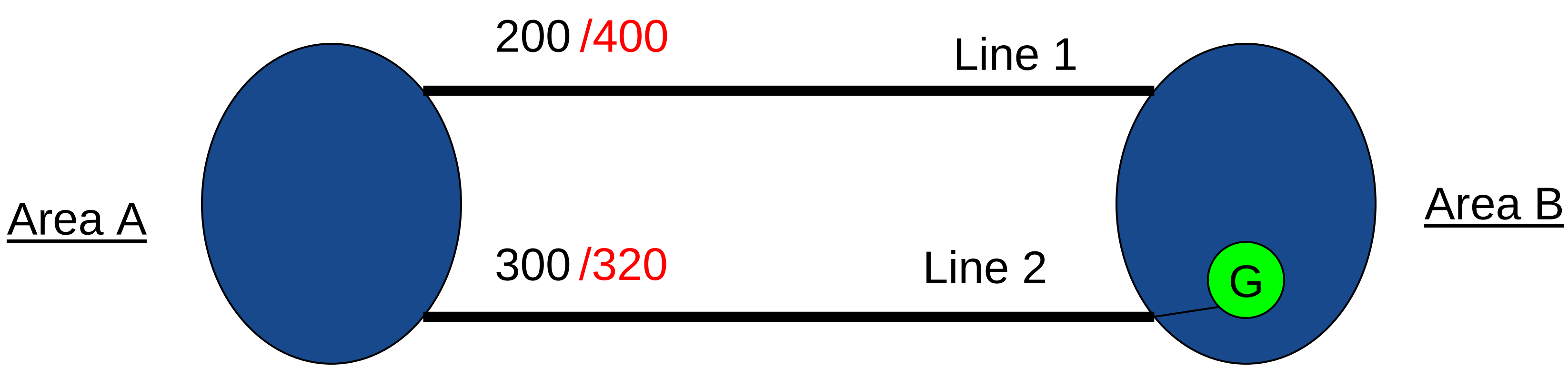
0 + 100% * 320 = 320

➔A to B transfers limit confirmed for this condition

Determination of System Capability – Simplified Example Wrap-up

- What is the ability to move power from A to B ("transfer capability")?
  - Line 1 with G on line and all transmission in-service can support 500 MWs
  - Line 2 with G off-line and all transmission in-service can support 333 MWs
  - Line 2 with Line 1 out can support 320 MWs

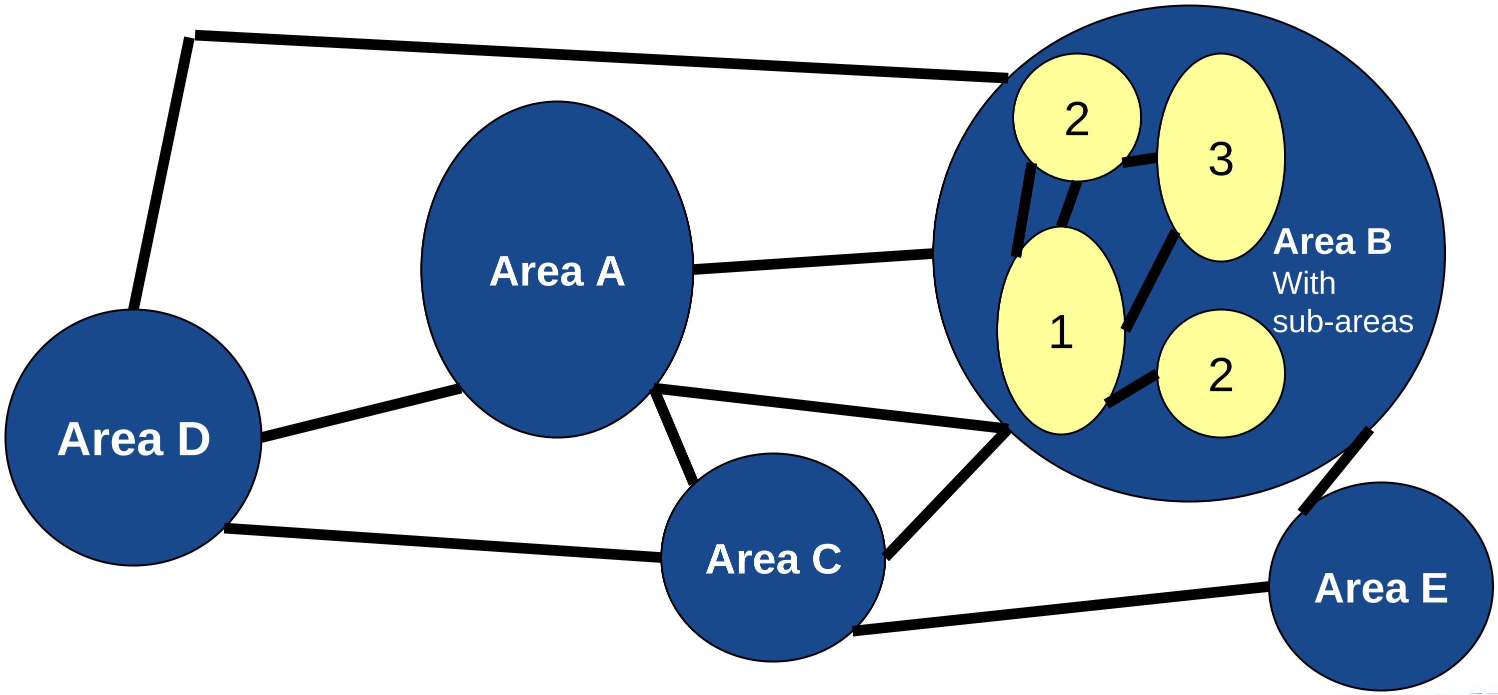
Transfer Limit for the Conditions Examined* = Overall Minimum = 320 MWs



**** Illustrative Example -- Not all conditions such as Line 1 out with Generator G off line examined in this example***

Determination of Transfer Capability – Not So Simple Illustration

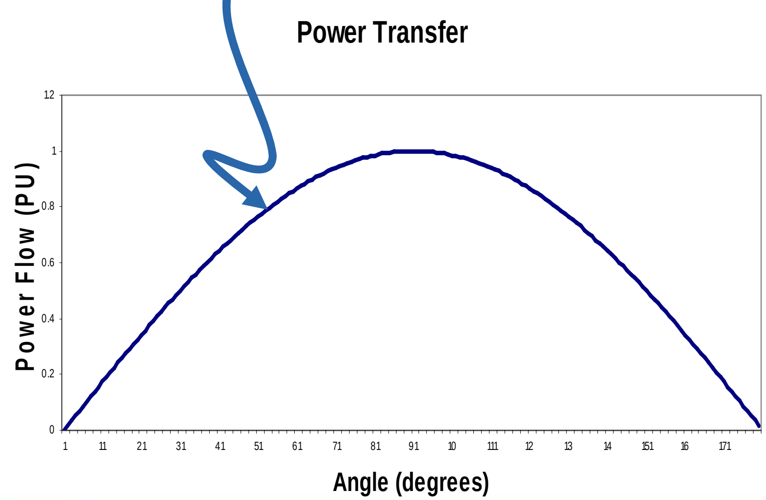
- Any facility can limit transfers – including lines between sub-areas
- Dispatch and load patterns throughout the area impact results – this includes "parallel" transfers
- Factors other than amount of flow in "normal" and N-1 states such as voltages, stability and ability of the system to remain reliable with higher order contingencies (NERC category C and D events) can be more limiting



Planning 101 Final Thoughts

$$P = V_1 \bullet V_2 \bullet \sin\delta / X$$

- Where *the real power that can flow through a line* is approximately equal to the product of the voltages at the ends of a line times the sine of the angle between the ends of the line, divided by the reactance of the line.
  - X is proportional to the length of a line.
  - X is effectively inversely proportional to the square of the transmission voltage.
- The grid is "self healing" up to about 30 degrees; operating transmission systems at the top of the curve is disastrous.



Planning Process: Future Oriented, Relies on Forecasts

Reliability Planning

Load Forecast

Meet Reliability Planning Criteria

NERC Criteria & Standards
ITC Criteria

1. Determine the ability of system to meet current and future reliability needs (Comply with NERC reqs)
2. Plan system upgrades to meet the need (fill gap)

Future System Changes
- Generation
- Transmission
- Distribution
- Market Flows

Unify Plans

Economic Planning

Fuel Forecast
Hourly Load Profile

Generation Unit Economic and Performance data

Make Market more Efficient

1. Determine the ability of system to economically and efficiently deliver power
2. Plan system upgrades to meet the need (fill gap)

Why a Robust Transmission System?

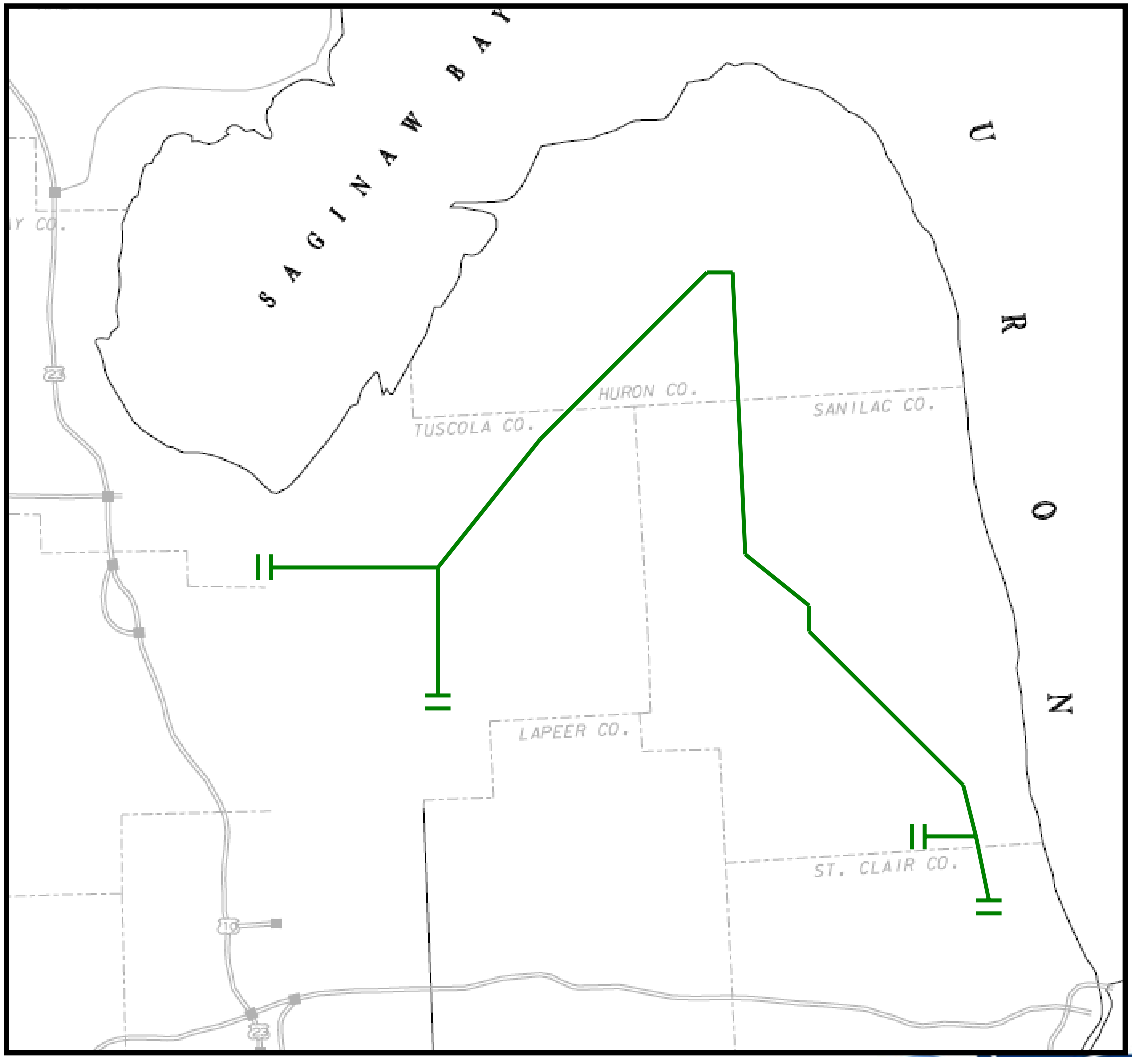
- Renewable resources
  - Move generation to load
  - Need to have a robust system in place to maintain reliability – these resources can pose non-traditional operating challenges
- Support Competitive Markets – Reduce Congestion
- Reliability -- The Grid must be reliable and secure

- FERC November 15, 2007 Open Commission Meeting Statement of Chairman Joseph T. Kelliher:

  “The United States does not have a Third World power grid. We have the most extensive bulk power system in the world. However, we do not have the grid we need to assure reliability and support competitive wholesale power markets.”

A Glance at Michigan's Thumb

- A possible area of interest for wind
  - Past generation interconnection queue requests
  - Wind maps
- Existing transmission
  - Served by a single circuit 120 kV loop
  - Wire capacity about 200 MWs – little unused capacity



Challenges in Evaluating Transmission Plans

- Transmission lines will be in place for 50+ years
  - Uncertainty grows with time
  - Current models go out 10 to 15 years
- Models assumption driven, benefit calculations depend upon:
  - Uncertain future load and generation patterns.
  - Future generation costs (e.g., capital and fuel costs)
  - Other transmission investments

FERC Order 890 – Purpose of Final Rule

- To strengthen the pro forma OATT (Open Access Transmission Tariff) to ensure that it achieves its original purpose of remedying undue discrimination
- To provide greater specificity in the pro forma OATT to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the Commission's enforcement
- To increase transparency in the rules applicable to *planning* and use of the transmission system. Order 890 mandates nine planning principles

Nine Planning Principles

Source: FERC Order 890 Fact Sheet

FERC Order 890 Planning Principles

1) ***Coordination –*** *Meet with Transmission Customers and Interconnected neighbors to develop a transmission plan on a non-discriminatory basis.*
2) ***Openness –*** *The planning process open to all affected parties*
3) ***Transparent –*** *Disclosure to all transmission customers and other stakeholders the basic criteria, assumptions, and data that underlie the transmission system plans.*
4) ***Information Exchange –*** *Transmission customers required to submit information on projected loads and resources that is needed for planning.*
5) ***Comparability –*** *After considering data and comments from customers and other stakeholders, develop a plan that a) meets the specific service requests of its transmission customers, b) treats similarly situated customers comparably in system planning, c) demand resources should be considered on a comparable bases to the services provided by comparable generator resources where appropriate*
6) ***Dispute Resolution –*** *Transmission provider to propose a dispute resolution process to manage disputes that arise from planning process rules.*
7) ***Regional Participation –*** *Transmission provider to coordinate with interconnected systems to a) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data, and b) identify system enhancements that relieve congestion or integrate new resources.*
8) ***Economic Planning –*** *Identify significant and reoccurring congestion and post studies on OASIS a) location and magnitude of congestion, b) possible remedies , c) cost of congestion, d) cost associated with relieving congestion*
9) ***Cost Allocation –*** *Address the allocation of cost of new facilities.*

Information Sharing

- Information sharing with stakeholders is subject to several important caveats:
  - Sharing of transmission information must not compromise homeland security.
  - Information shared with one market participant must be available to all market participants.
  - Material that is not appropriate for public distribution must be protected (e.g., trade secrets, SEC requirements, etc.).

Elephant-Sized Problem

We have an **elephant-sized problem**:

1. We **operate** today's system **closer to the edge** than ever before…

2. We **need a transmission network** to support the amount of renewable energy options that are available to us…

3. We're sitting on the **precipice of climate change legislation**, which will change all of that. So, it is in that context that we believe that the grid will be **threatened unless we build the transmission** infrastructure that is necessary to **support renewable resources like wind**, that will enable us to locate new **clean coal facilities** -- or even the gas facilities -- to **locate them in places in which the grid will be able to withstand** that so that we can meet the load requirements as they grow and have a **reliable system**…

- Richard P. Sergel, president and CEO of the North American Electric Reliability Corporation (NERC)

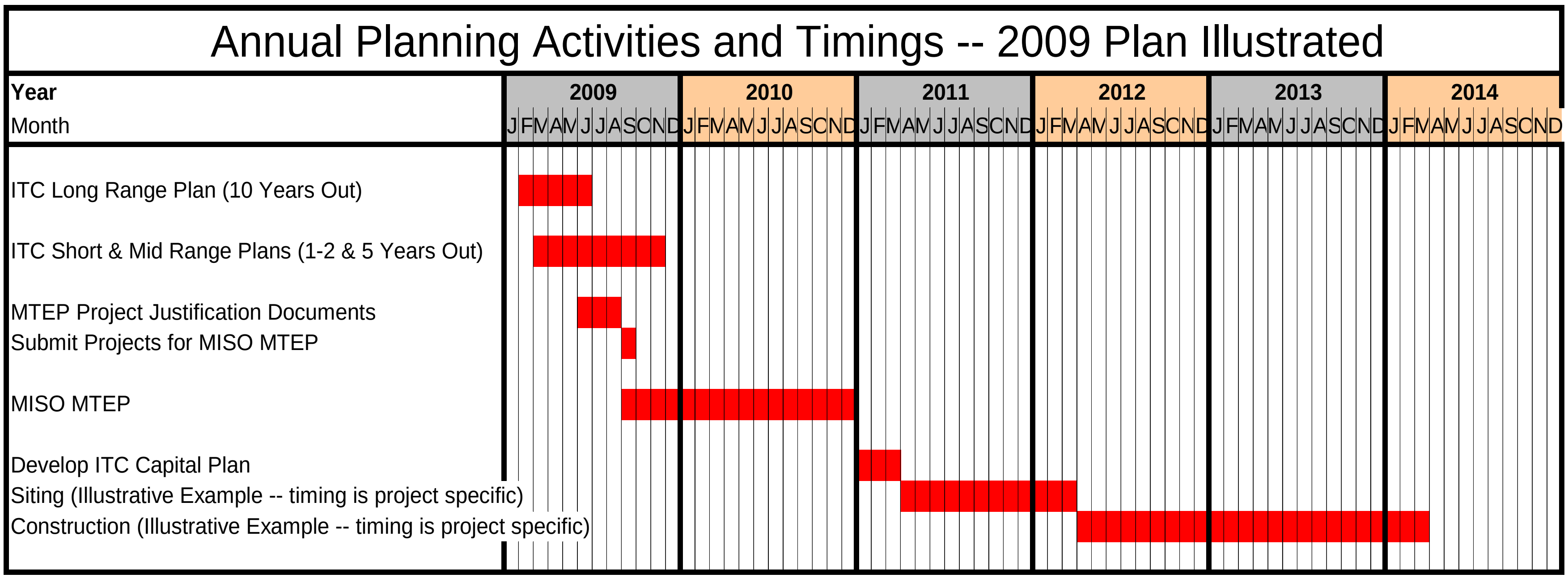
Midwest ISO's Role with ITC

- ITC plans transmission projects based on load forecasts, reliability issues and known transmission constraints.
- Transmission projects are vetted through the Midwest ISO stakeholder process.
- Midwest ISO reviews the impact and benefits of each proposed transmission project.
- Midwest ISO incorporates approved projects into their Midwest Transmission Expansion Plan (MTEP) plan for the year.
- ITC moves forward in implementing approved transmission projects.

Project Process – Implementation of Generation Interconnection Queue

- Generation interconnection queue
  - Ad hoc study initiated according to interconnecting generator queue request
  - Focuses on shorter term needs – does not comprehensively look at all reasonably potential generation additions, just some of those in queue
  - Queue studies results in plan development
- Not focused on overall planning – focused on getting next generators on line

Project Process – Implementation of Forward Plans Via MTEP



Impact of State/MPSC Actions

- **Nothing:** Rely on Midwest ISO Generation Interconnection Queue
- **Reduce Siting Time:** Provide Support for Forward Projects in Midwest ISO's MTEP
- **Reduce Plan Development, Midwest ISO MTEP and Siting Time:** Provide Support for Forward Projects in Midwest ISO's MTEP, support "Out-of-Cycle" Review