MI POWER GRID

Making the Most of Michigan's Energy Future

Transmission Planning

Advanced Planning Stakeholder Meeting
January 19, 2020

MPSC
Michigan Public Service Commission

Workgroup Instructions

1. This meeting is being recorded.

2. Please be sure to mute your lines.

3. There will be opportunities for question/comments after each of the sections identified in the agenda. Please type questions into the chat function or use the “raise hand” function during this time. We will open it up to those on the phone after those using the chat function.

4. We will be requesting comments after all meetings. Comments will be posted to the webpage.

5. The presentations for all meetings are posted to the Advanced Planning webpage.

6. If you are having technical difficulty, please contact Kyle Daymon at DaymonK@michigan.gov.

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Making the Most of Michigan's Energy Future

Agenda Items		
1:00 pm	Introduction	Naomi Simpson (MPSC)
1:10 pm	Transmission Planning Overview	Marc Keyser (MISO)
1:30 pm	MPSC Energy Markets Overview	Bonnie Janssen (MPSC)
1:50 pm	Incorporating Risk in the Transmission Planning Process	Anish Gaikwad (EPRI)
2:35 pm	Break	
2:45 pm	Transmission Planning and IRP	Erin Buchanan & Drew Siebenaler (Xcel Energy)
3:05 pm	Transmission Owner Perspectives – Transmission and IRP	Kwafo Adarkwa (ITC) Kamran Ali (AEP) Heather Andrews & Robert Morton (ATC)
3:50 pm	Open Discussion	Zach Heidemann (MPSC)
4:15 pm	Closing	Naomi Simpson (MPSC)
4:30 pm	Adjourn	

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MISO Transmission Planning and Cost Allocation

January 19, 2021

The transmission planning process provides a comprehensive approach to identify grid needs

Regional Planning
Long-term regional planning based on future scenarios

Policy Assessment
Analyze policy change; determine transmission required to support policies

MISO Value-Based Planning Approach

Resource Planning
Evaluate long-term interconnection queue requests; identify upgrades to integrate into base expansion model

Local Planning
Validate plan needs identified by Transmission Owners; seek efficiencies in planning; evaluate system against reliability standards

MISO's transmission planning process is executed according to a set of guiding principles

Develop a transmission plan that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs

Make the benefits of an economically efficient electricity market available to customers by identifying transmission projects which provide access to electricity at the lowest total electric system cost expansion plan that meets reliability needs, policy needs, and economic needs

Analyze system scenarios and make the results available to state and federal energy policy makers and other stakeholders to provide context to inform regarding choices

Fundamental Goal

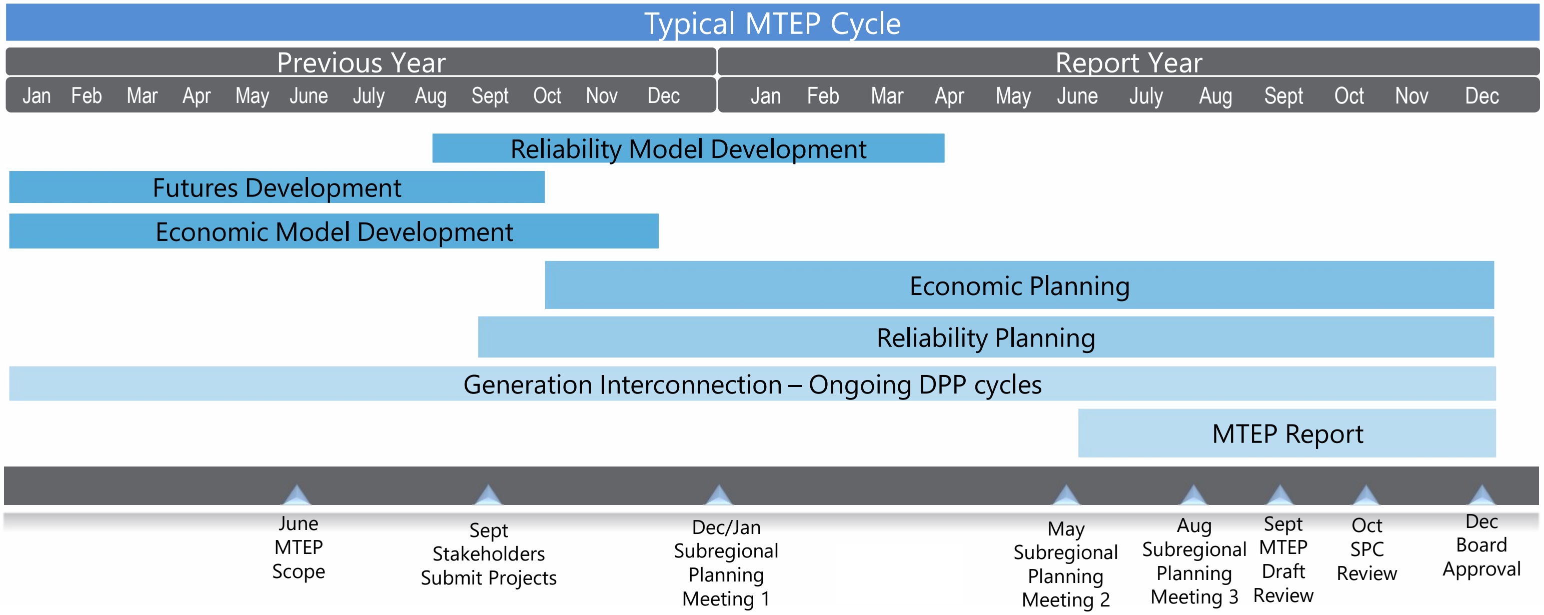
The development of a comprehensive expansion plan that meets reliability needs, policy needs, and economic needs

Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects

Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations

Support state and federal energy policy requirements by planning for access to a changing resource mix

MTEP and Generator Interconnection Cycle Timelines



Typical MTEP Cycle

Previous Year: Jan Feb Mar Apr May June July Aug Sept Oct Nov Dec

Report Year: Jan Feb Mar Apr May June July Aug Sept Oct Nov Dec

Reliability Model Development

Futures Development

Economic Model Development

Economic Planning

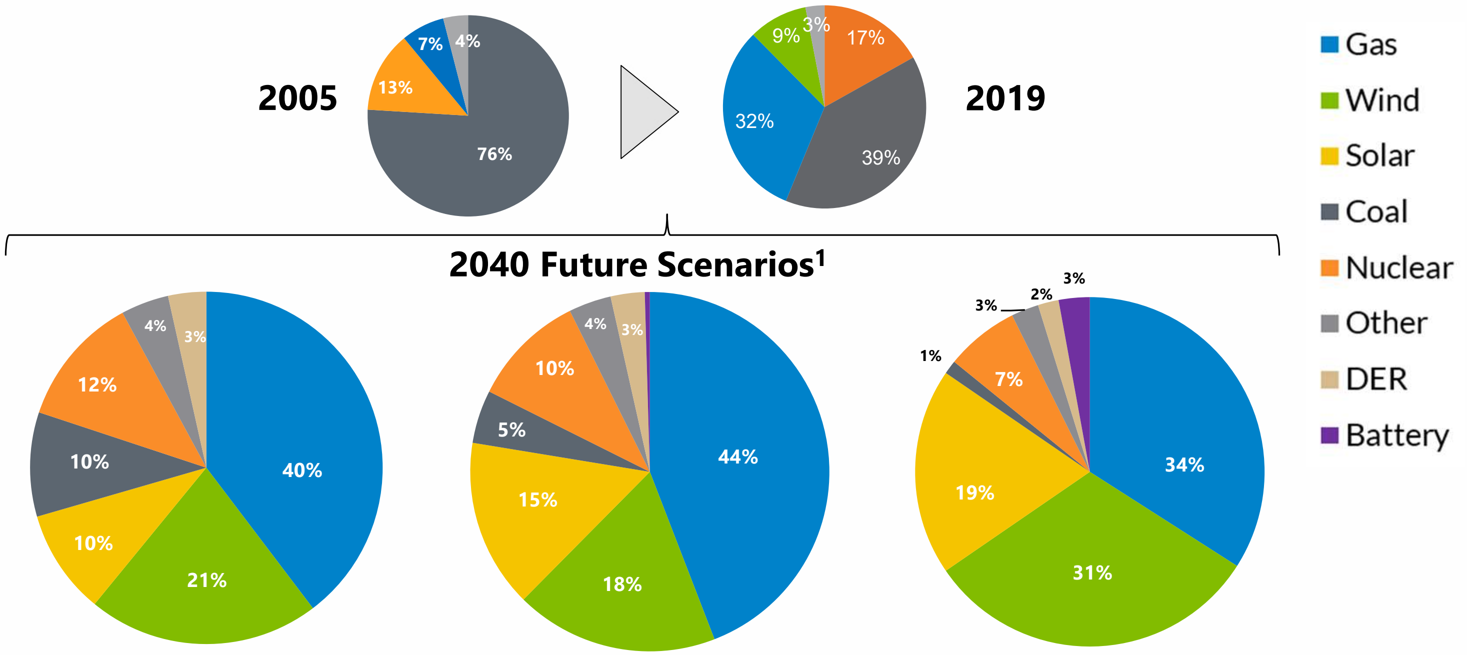
Reliability Planning

Generation Interconnection – Ongoing DPP cycles

MTEP Report

- June MTEP Scope
- Sept Stakeholders Submit Projects
- Dec/Jan Subregional Planning Meeting 1
- May Subregional Planning Meeting 2
- Aug Subregional Planning Meeting 3
- Sept MTEP Draft Review
- Oct SPC Review
- Dec Board Approval

Three MISO Futures are created to be utilized in the MTEP Analysis



Future 1
Footprint develops in line with 100% of utility IRPs and 85% of utility/state announcements, etc. Emissions decline as an outcome of utility plans. Load growth consistent with trends.

Future 2
Companies/states meet their goals, mandates, etc. Footprint-wide CER[2] of 60% by 2040. Energy increases 30% footprint-wide by 2040, driven by electrification.

Future 3
Changing federal and state policies support footprint-wide CER of 80% by 2040. Increased electrification drives a footprint-wide 50% increase in energy by 2040.

1. *Energy mix outputs from EGEAS do not consider transmission constraints*
2. *Carbon emissions reduction (CER) from 2005 baseline*

Transmission Cost Allocation

Project Type	Description	Allocation to Beneficiaries
Multi-Value Project	Above 100 kV and project cost of $20 million or more, evaluated as part of a portfolio of projects and must meet one of three criteria	100% postage stamp to load
Market Efficiency Project	230 kV and above and project cost of $5 million or more, reduce market congestion when benefits are 1.25 in excess of costs	100% distributed to zones commensurate with expected benefit, based on the benefit metrics described in Attachment FF-7
Baseline Reliability Project	NERC Reliability Criteria	100% allocated to local Transmission Pricing Zone
Generation Interconnection Project	Interconnection Request	Primarily paid for by requestor; 345 kV and above 10% postage stamp to load.
Transmission Delivery Service Project	Transmission Service Request	Generally paid for by Transmission Customer; Transmission Owner can elect to roll-in into local Transmission Pricing Zone rates
Participant Funded	Projects that are funded by a Market Participant	The Market Participant funds the project.
Other	Project that does not qualify under other project categories.	The costs of these projects are recovered in zonal rates.

Planning Highlights in Michigan

Projects Approved in MTEP20

Project Type	Number of Projects	Estimated Cost
Baseline Reliability Project	31	$ 166,613,000.00
Generator Interconnection Project	13	$ 107,010,143.43
Other	39	$ 162,380,389.00
Grand Total	**83**	**$ 436,003,532.43**

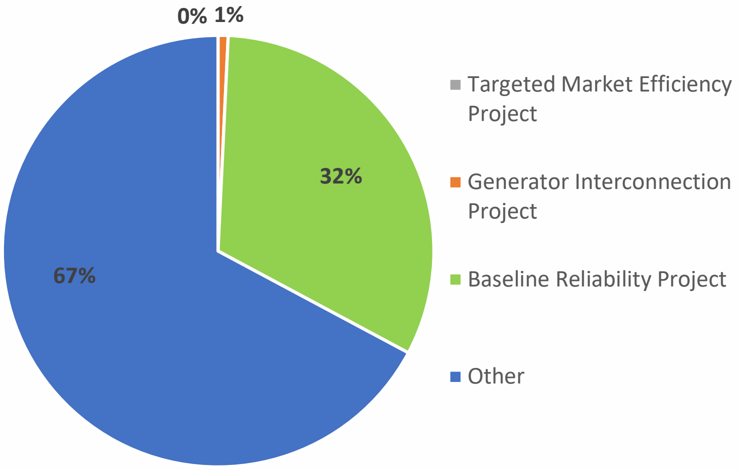
Projects Not In-Service from previous MTEP cycles

Project Type	Estimated Cost	% of Total
Targeted Market Efficiency Project	$ 110,000.00	0.01%
Generator Interconnection Project	$ 15,739,440.00	0.76%
Baseline Reliability Project	$ 667,549,595.87	32.06%
Other	$ 1,398,882,166.17	67.18%
Grand Total	**$ 2,082,281,202.04**	**100.00%**

Notable Projects in Michigan:

- MTEP17 P14265 TMEP - Monroe – Bayshore 345 kV
  - Interregional project cost-shared with PJM

Previous MTEP Approved Projects Not In-Service (Estimated Cost)



Data available on https://www.misoenergy.org/planning/planning/mtep20/ > Appendices Tab
Appendix A and Appendix A-3

Questions

MI PSC Staff Participation in RTO Transmission Planning

Bonnie Janssen 1/19/2021

MI PSC Staff Participation in Transmission Planning

- MISO
  - Organization of MISO States (OMS)
  - Staff of Individual Commissions
- PJM
  - Organization of PJM States, Inc. (OPSI)
  - Individual Commissions do participate
- FERC
  - OMS or OPSI members
  - Individual Commissions

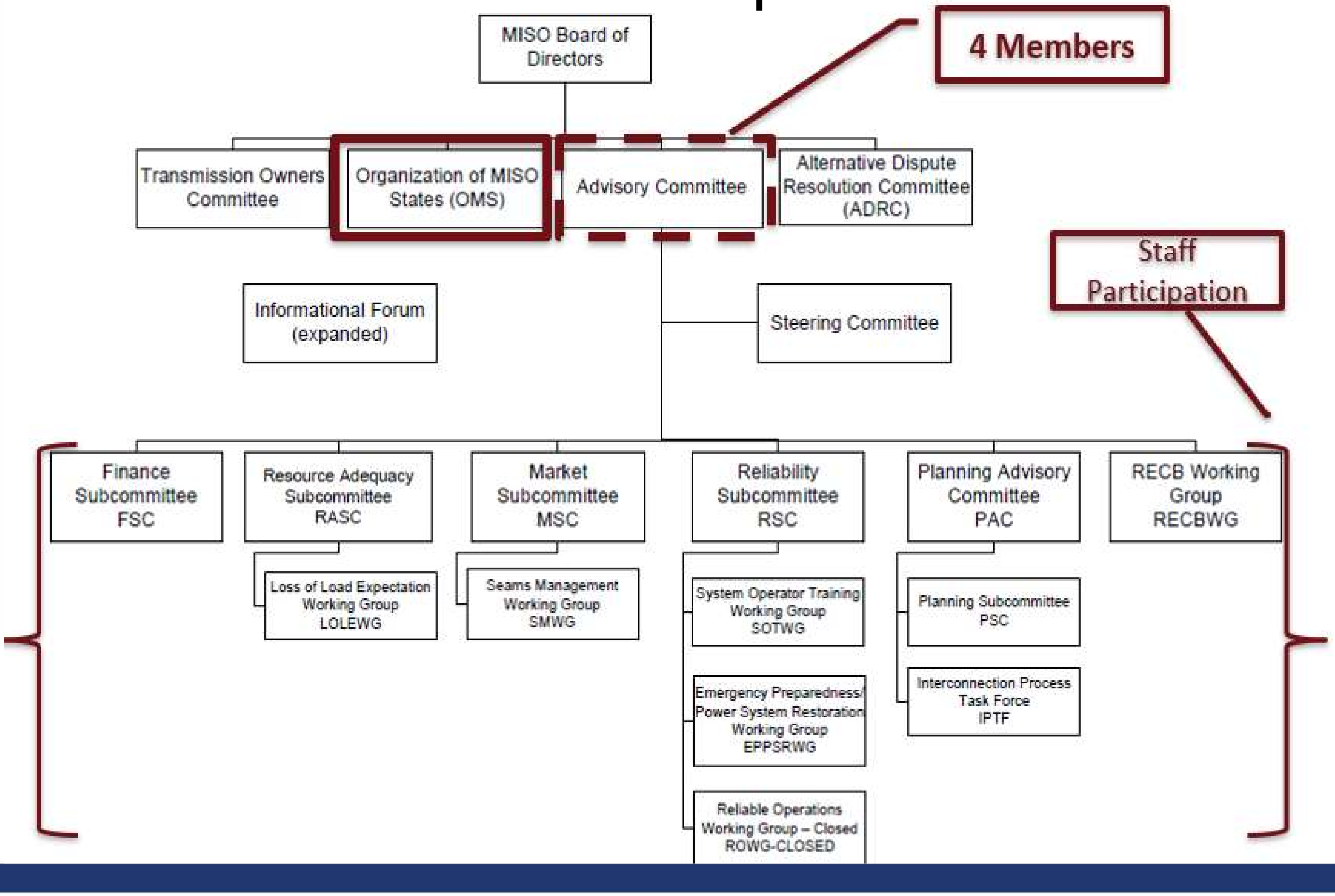
Who are OMS and OPSI?

- OMS
  - Indiana not-for profit, tax exempt 501(c)(4) established 2003
  - Members are retail energy regulators in MISO (15 states, 1 province, and 1 city)
    - Retail electric or distribution rate jurisdiction, **OR** Primary siting authority
  - Associate Members (non-voting)
    - Consumer Advocates
    - Energy Planning Offices
    - Agencies involved in energy related environmental issues, or others as approved
- OPSI
  - Delaware non-profit corporation established in 2005
  - Members are utility regulators in PJM (13 states and Wash D.C.)
  - Retail electric or distribution rate jurisdiction of TO members or TDU members of PJM RTO

What OMS and OPSI do?

- OMS/OPSI members coordinating data/issues analyses and policy formulation related to MISO/PJM, its operations, its Independent Market Monitor (IMM), and related FERC filings.
- While the 17 OMS Members/14 OPSI Members interact as a regional body, their collective actions as OMS/OPSI do not infringe on each of the 14 agencies' individual roles as the statutory regulators within their respective state boundaries.
- Collective interest of retail regulators can be more effective before MISO, PJM and FERC than by individual interests
- These two groups expand the resources available to regulators
  - Share workload
  - Utilize expertise from other states
  - Improve state regulation through better comprehension of wholesale markets
  - Travel funding
- MI PSC staff actively participates in MISO/PJM meetings and provide feedback if OMS/OPSI do not provide feedback or if our position is different than OMS/OPSI’s

OMS/MI PSC Participation at MISO



MISO Board of Directors

Transmission Owners Committee

Organization of MISO States (OMS)

Advisory Committee

Alternative Dispute Resolution Committee (ADRC)

4 Members

Staff Participation

Informational Forum (expanded)

Steering Committee

Finance Subcommittee FSC

Resource Adequacy Subcommittee RASC

Loss of Load Expectation Working Group LOLEWG

Market Subcommittee MSC

Seams Management Working Group SMWG

Reliability Subcommittee RSC

System Operator Training Working Group SOTWG

Emergency Preparedness/Power System Restoration Working Group EPPSRWG

Reliable Operations Working Group – Closed ROWG-CLOSED

Planning Advisory Committee PAC

Planning Subcommittee PSC

Interconnection Process Task Force IPTF

RECB Working Group RECBWG

MI PSC Staff Participation in MISO

- Under the Planning Advisory Committee (PAC)
  - MISO Transmission Expansion Planning (MTEP)
  - Interconnection Process Working Group (IPWG)
  - Planning Subcommittee (PSC)
- Michigan is in three Local Resource Zones (LRZs or Zones)
- Lower Peninsula is Zone 7, and in the East Sub Regional Planning Meetings (SPMs)
- Upper Peninsula is 10% of Zone 2 and <1% of Zone 1 and in the West SPMs
- There is also a Central and South Region
- MISO hosts 3 SPMs for each region between January-September and 2-4 Michigan Technical Study Task Forces (CEII/NDA are usually needed) due to confidential information on reliability/voltage/thermal issues

Subregional Planning Meetings

- MISO/PJM must host a series of SPMs from Order 890 to encourage an open and transparent planning process
- MISO/PJM presents the Transmission Owner (TO) projects at this local level, and stakeholders participate by asking questions, providing alternatives, or operating manual changes, and open discussion of issues that drive new Transmission expansion on the grid
- Stakeholders check system data for accuracy, respond to data requests, review models, provide feedback, and suggest process improvements.

Stakeholders at Michigan SPMs

- ATC, ITC, METC, Wolverine, I&M, NSP
- DTE, Consumers, I&M, UPPCO, UMERC
- MPPA, ABATE, CARE,
- Cities,
- MI PSC staff
- Outside of MI stakeholders—regulatory staff, LSEs, TOs, etc.

MISO Transmission Planning Process

- Model development
- Transmission to transmission interconnections
- Interregional coordination with other T planning RTOs
- System Support Resource studies for unit suspension or retirement
- Other focus studies (CIL-CEL study)
- Planning:
    - Transmission service
    - Generator Interconnection
    - Load interconnection
    - Market congestion
- https://www.misoenergy.org/legal/business-practice-manuals/

Non-transmission alternatives (NTAs)

- Most of MISO is vertically integrated
- Michigan, Iowa and Wisconsin have independent TOs
- More discussion on T projects in these states since not vertically integrated that have T, G, D all in-house with competing projects based upon payback, reliability, load needs, etc.
- MI PSC and EDCs support discussion on NTAs

MI PSC Staff Participation in PJM

- PJM Regional Transmission Expansion Planning (RTEP)
- Similar Project categories and drivers to MISO
  - Baseline
    - Reliability, market efficiency, public policy drivers
  - Network
    - All upgrades- new service requests
  - Supplemental
    - All other changes NOT required to meet PJM criteria above
- State Agreement Approach
  - The primary way to explicitly incorporate a state(s) public policy goals
    - This has only been used once, in 2020 by New Jersey
  - By selecting this method, the state(s) also agree to cover the costs of any needed projects
- Michigan is 22% of I&M and 0.6% total of PJM sales (2019)

Questions

- Bonnie Janssen
- janssenb@Michigan.gov

Incorporating Risk in Transmission Planning

Presentation for MI Power Grid Advanced Planning Processes Workgroup

Anish Gaikwad
Program Manager, Transmission Planning

Jan-19-2021

www.epri.com

Outline

- Introduction
- Risk and transmission reliability considerations
- Risk and transmission resiliency consideration
- Takeaways

Transmission Systems – Large Interconnected Networks

Transmission systems are large, interconnected networks of high-voltage (typically above 69 kilovolts (kV)) lines and substations with voltage transforming transformers and associated equipment. They carry large quantities of electricity from utility-scale generators to low-voltage lines in distribution systems, which then connect to load.

Transmission planning is an ongoing process of assessing the electric system in its ability to deliver electricity as economically as possible while maintaining an acceptable level of reliability to meet future demand; and accommodate new generation encompassing various technologies.

Control center

Generation stations

Voltage stepping up

Interconnected transmission system

Voltage stepping down

Distribution system

- Generation
- Voltage step up transformers
- High voltage transmission lines
- Voltage step down transformers
- Low voltage distribution line
- Low voltage Loads

Why is Transmission Planning Important in Today's Context?

Transmission planning is even more critical and challenging today than it was even 10 years ago.

Climate change related impacts on load and other assets

Significant rise in energy resources which are connected on distribution system near the consumer and are distributed (**DER**)

Emergence **battery energy storage** technologies on transmission and distribution systems which can store as well as provide energy

Changing nature of end-use load such as electric vehicles, data centers

Replacement of fossil plants with significant increase in transmission connected wind and solar resources which are typically remote from where the electricity is consumed

Natural and man-made extreme events which can be more menacing than in the past due to their increase frequency and severity

How is Transmission Reliability Assessed?

Transmission security

- ensures reliable system operation in the face of contingencies such as the loss of generation or transmission
- primary focus of transmission planning

Focus of the presentation today

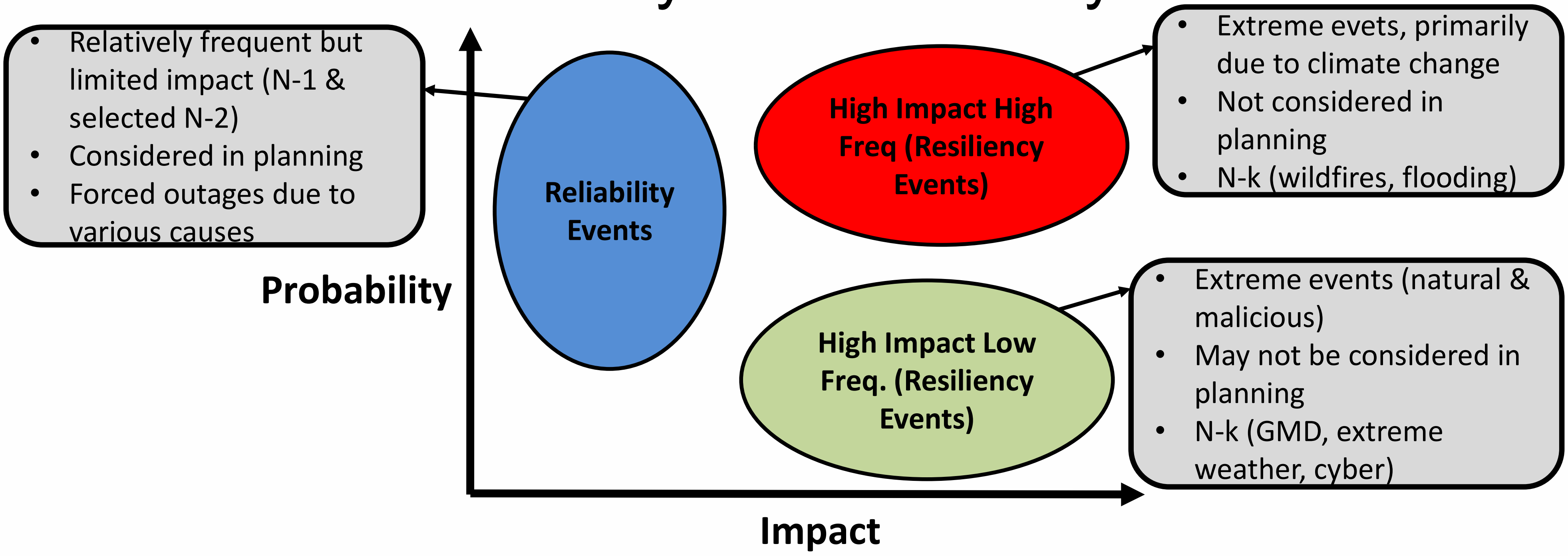
+

Resource adequacy

- ensures that there will be adequate generation or demand-side resources to meet the aggregate electric energy demand requirements of customers at all times.
- primary focus of resource planning—the planning of adequate supplies of generation and demand-side resources

=

Reliability and Resiliency



- Relatively frequent but limited impact (N-1 & selected N-2)
- Considered in planning
- Forced outages due to various causes

Probability

Reliability Events

High Impact High Freq (Resiliency Events)

- Extreme evets, primarily due to climate change
- Not considered in planning
- N-k (wildfires, flooding)

High Impact Low Freq. (Resiliency Events)

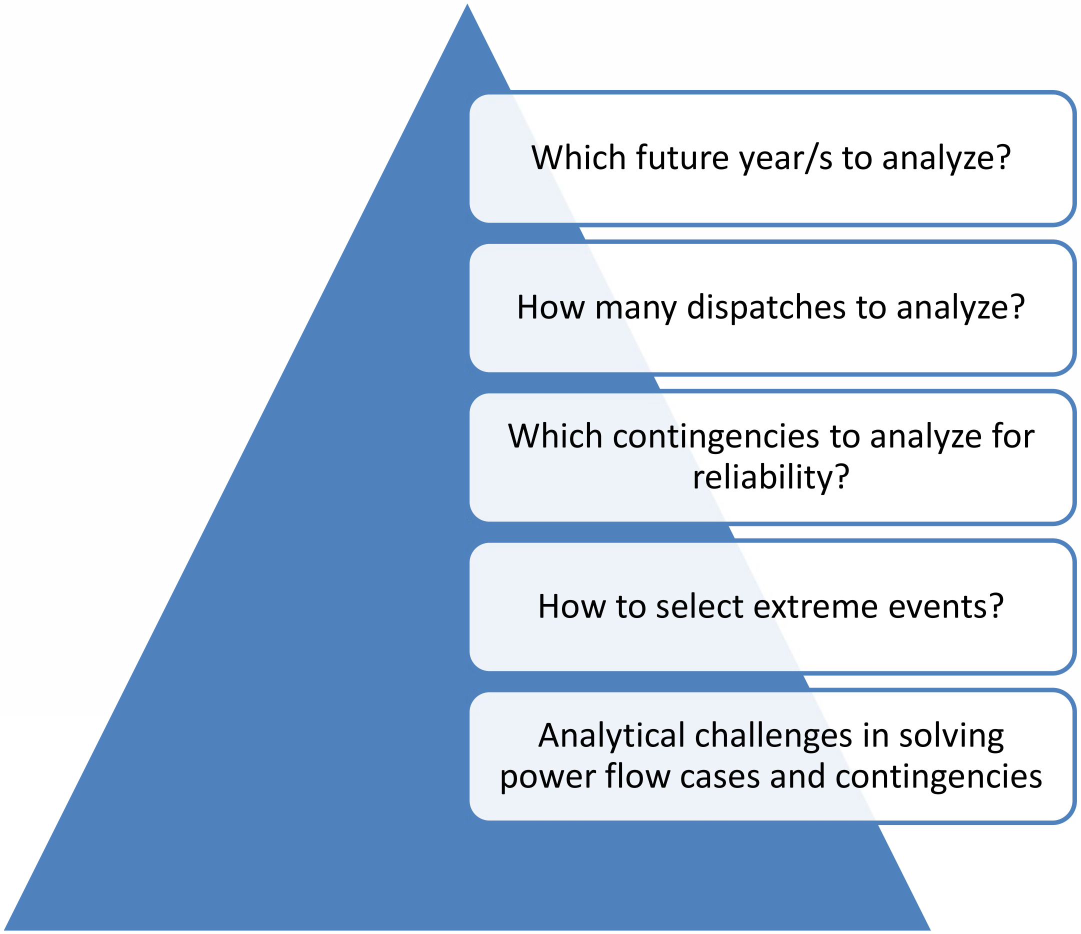
- Extreme events (natural & malicious)
- May not be considered in planning
- N-k (GMD, extreme weather, cyber)

Impact

Can projects proposed for reliability also help to improve system resiliency and vice-a-versa?

Is there a way to compare multiple projects across various reliability & resiliency events?

Multi-Dimensional Nature of the Problem



Which future year/s to analyze?

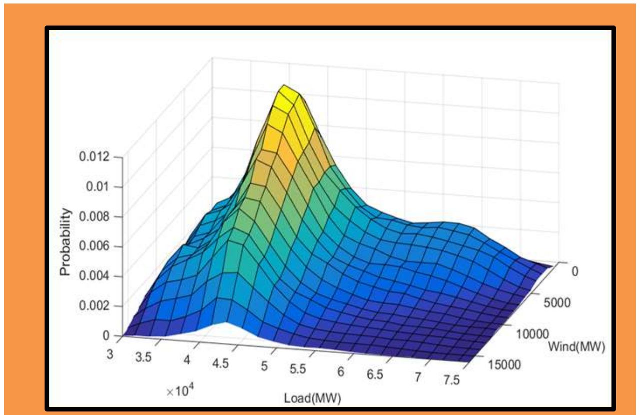
How many dispatches to analyze?

Which contingencies to analyze for reliability?

How to select extreme events?

Analytical challenges in solving power flow cases and contingencies

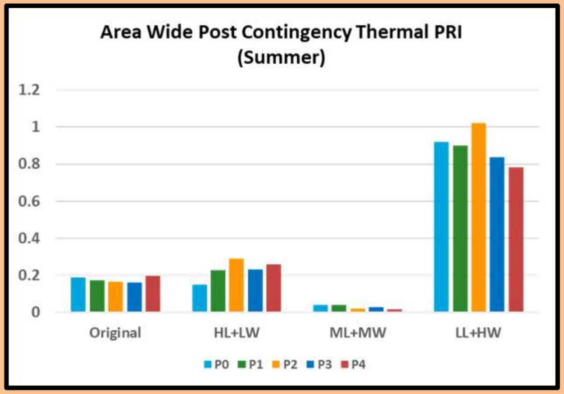
Risk-Based Reliability Assessment Framework



Develop Scenarios

Compile historical profiles of load, renewable, demand-side resources to develop power flow cases by season

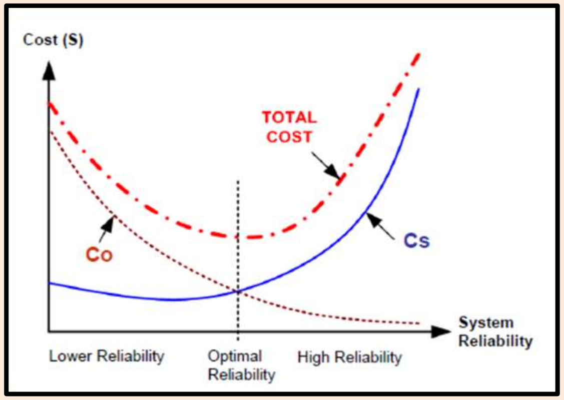
EPRI Scenario Builder Framework



Analyze Each Scenario

Enumerate contingencies to probabilistically assess reliability of **each** scenario with and without reinforcement options

Siemens PTI PSS®E

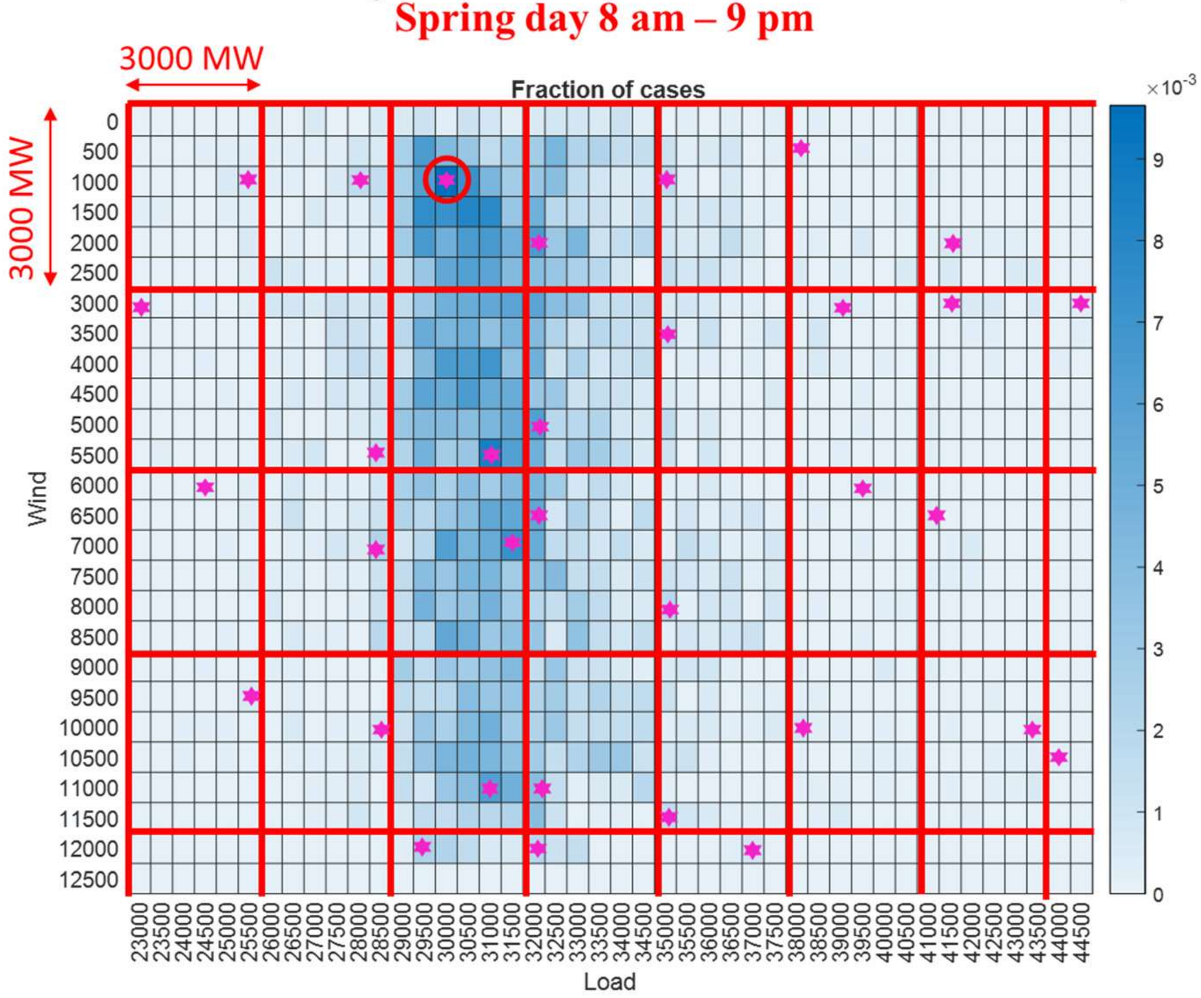


Cost-Benefit Analysis

Cost-benefit analysis of reinforcement options

Net Present Worth Analysis

How Many Scenarios to Assess Depends on System Variability



- **Historical as well as forecasted profiles of renewable generation and load can be used to develop power flow scenarios**

Selecting cases from the joint probability distribution

Ex: No. of the snapshots in the 0-3000 MW wind and 29000 - 32000 MW load bin = 551, total number of snapshots =3626. Therefore the probability of snapshot **circled in red** is 551/3626 = 0.1520

Summation of probabilities of all **magenta stars = 1**

33 cases chosen in total

- **Need better approaches for clustering thousands of load-renewable generation data points**
- **Developing AC feasible cases in quite challenging!!**

Risk-Based Reliability Assessment

Each Power Flow Scenario

- Multiple power flow scenarios with and without proposed transmission projects

Solve PF for Contingency List

- State enumeration approach to develop contingencies (thousands depending on study area, number of elements to trip per contingency)
- Solve PF for each Contingency

Remedial Actions (if violations)

- If violations occur for a contingency, run remedial actions to limit impact (generation re-dispatch, tap adjustment, shunt switching, load drop)

Reliability Indices

- Accumulate Probabilistic Reliability Indices (PRI) across all cases, as well as compute load loss

$$\boldsymbol{PRI(voltage) = \sum Prob * voltage\ impact}$$

$$\boldsymbol{PRI(thermal) = \sum Prob * thermal\ impact}$$

An Example Case Study to Compare Projects

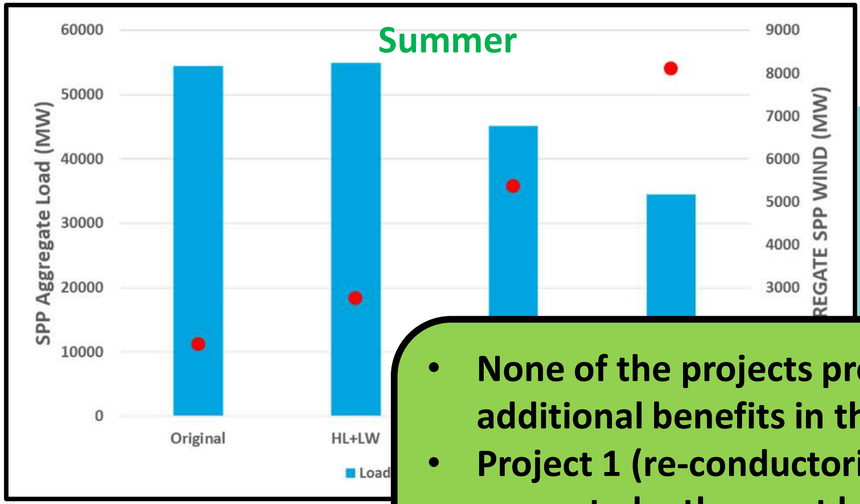
- **Problem: Overload of a 115 kV line for an N-1 contingency needed to be resolved**
- **Proposed reinforcement options:**

P1 Project	$	Rebuild of a 115 kV transmission line
P2 Project	$$	New 345 kV transmission line between substations A and B
P3 Project	$$	New 345 kV transmission line between substations C and D
P4 Project	$$$	New 345 kV transmission line between substations E and F New 345 kV/230 kV transformer at substation E

Compare the system-wide benefits of the different investment options using a risk-based framework and find the best value option

Developing Dispatch Cases

Total of 40 (20 per season) power flow cases



SUMMER and SPRING

scenarios

Original (base)

High Load + Low Wind

Med load + Med wind

Project 0

Project 1

Project 2

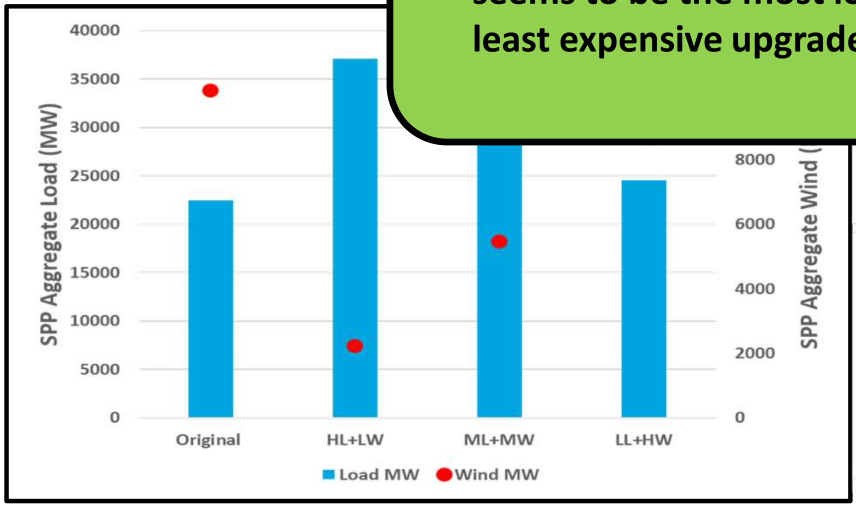
Project 3

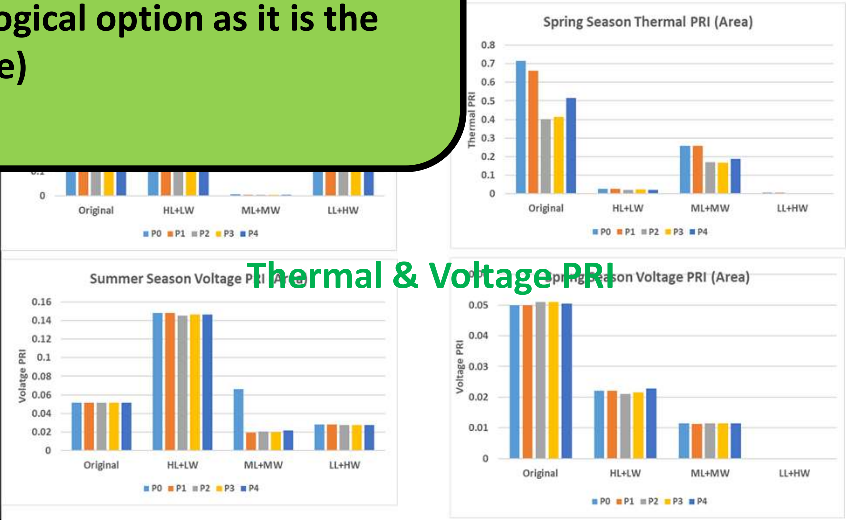
Project 4

Contingency Analysis

4 projects + no project

- None of the projects provide any significant additional benefits in the example
- Project 1 (re-conductoring of the 115kV line) seems to be the most logical option as it is the least expensive upgrade)



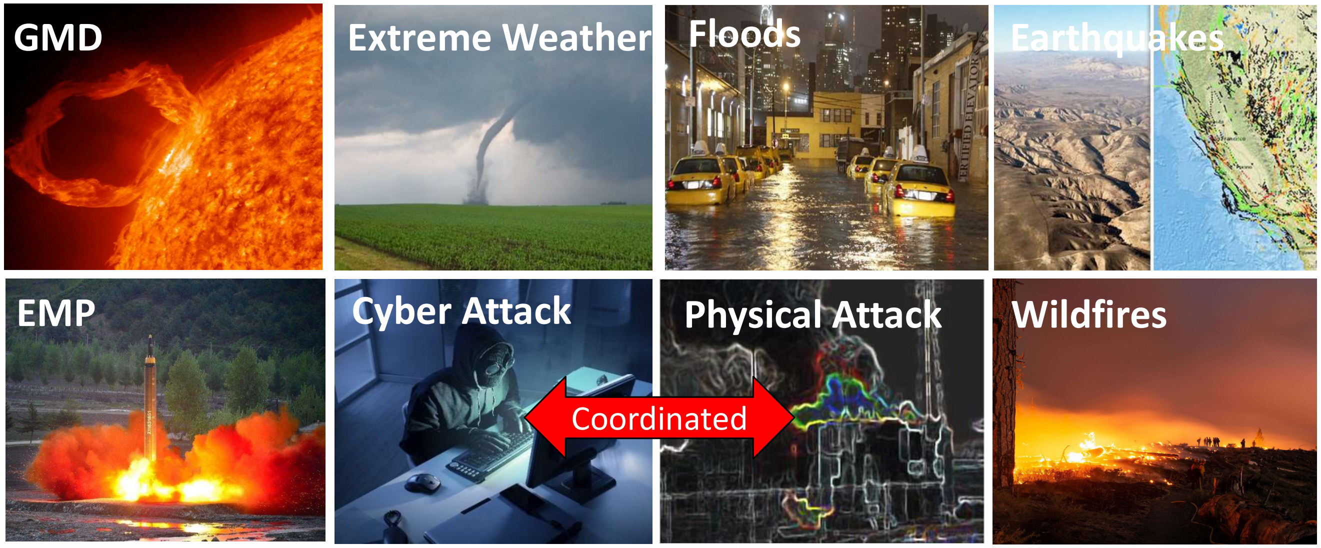


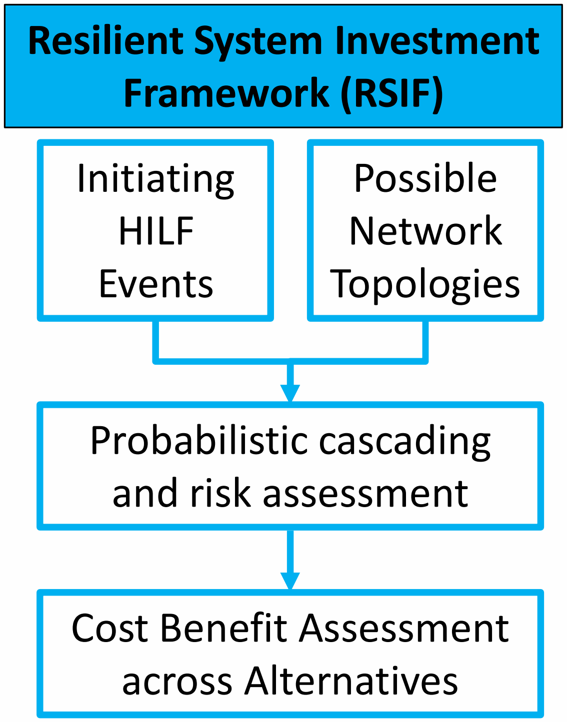
Thermal & Voltage PRI

A Risk-Based Framework for Resiliency Analysis

Resilient System Investment Framework

High Impact Low Frequency (HILF)





Resilient System Investment Framework (RSIF)

Initiating HILF Events

Possible Network Topologies

Probabilistic cascading and risk assessment

Cost Benefit Assessment across Alternatives

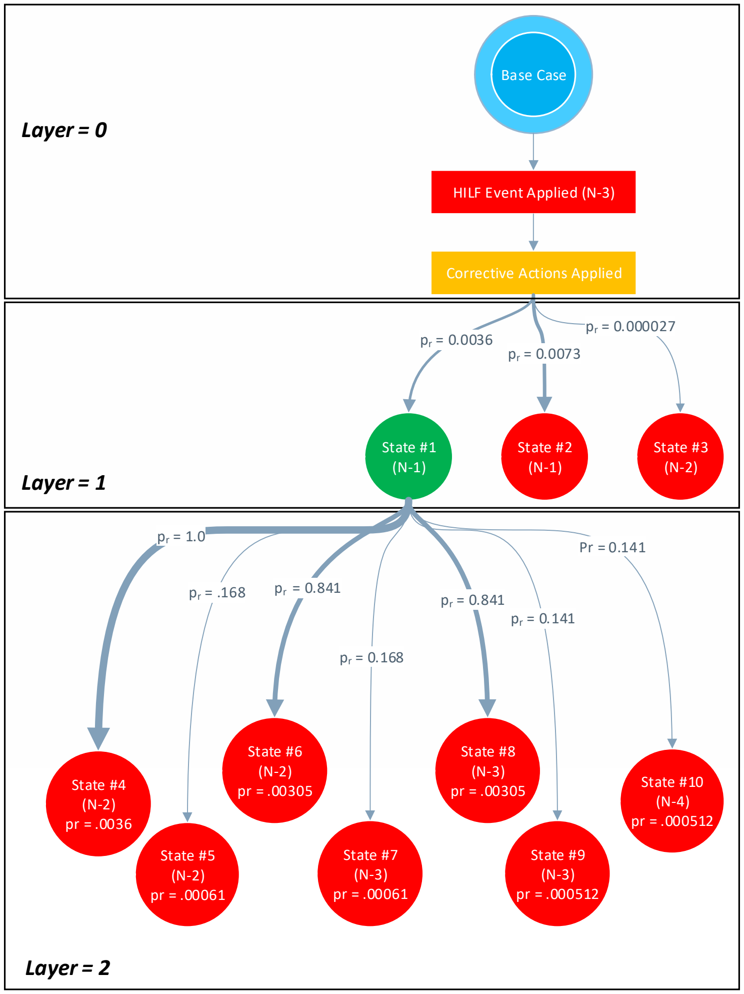
Which transmission investment options hedge the most risk from HILF events while also supporting reliability?

PCA Example Results

- ***@Layer = 0*** – HILF event applied to the base case and corrective actions implemented
- ***@Layer = 1*** – Post-HILF network evaluated for violations
  - Two elements violate limit criteria ($2^2 - 1 = 3$ new contingency states)
  - Contingency states evaluated for new violation and passed contingency enumeration module
- ***@Layer =2*** – State #1 only state to have new violations
  - Three elements violate limit criteria, 7 new states
- ***@Layer = 2*** – 7 states have no violations, simulations terminate

Each end state has a probability of occurrence and is compared against the intact base case to determine severity (differences in load and generation).

$$Risk = Probability * Severity$$



RSIF Application – Network Reinforcement Evaluation

- Evaluate possible network reinforcements to identify which project mitigates the most risk in response to a set of HILF events
- For example, across the 4 projects below, which project hedges the most risk and would provide the largest net present value (NPV) to the system
- **Extreme Events: Failure of 345 kV station outages**

$

P1 Project

- Rebuild of a 115 kV transmission line

$$

P2 Project

- New 345 kV transmission line between substations A and B

$$

P3 Project

- New 345 kV transmission line between substations C and D

$$$

P4 Project

- New 345 kV transmission line between substations E and F
- New 345 kV/230 kV transformer at substation E

RSIF Application – HILF Impact Analysis

Risk of load/gen loss due to HILF event (Layer = 0):

- Load loss risk same across the cases
- Generator loss risk is similar across the cases
- Risk at this layer is a direct reflection of the event impact ($p_r = 1.0$)
    - ~ 98% of the total risk is at Layer = 0 (i.e. no cascading)

Case	Cumulative Load Loss Risk	Cumulative Gen Loss Risk
Base Case	126.24	309.90
Proj 1	126.24	308.63
Proj 2	126.24	318.80
Proj 3	126.24	317.95
Proj 4	126.24	311.28

Key Takeaways:

- ***None of the projects were designed to harden the system***
- ***No impact on mitigating risk associated with the initiating HILF event***
- ***Overall the system is robust, the extreme initiating events do not cascade***

RSIF Application – Cascading Impact Analysis

Risk from subsequent cascades (Layers > 1):

- Not much impact of projects on subsequent cascading
- Lower cumulative risk due to significantly lower probability of occurrence

Case	Cumulative Load Loss Risk	Cumulative Gen Loss Risk	Load Loss Risk Mitigated	Gen Loss Risk Mitigated
Base Case	2.6438	4.3763	**NA**	**NA**
P1	2.5547	4.2033	**3.4%**	**4.0%**
P2	2.6198	4.4889	**0.9%**	**-4.3%**
P3	2.6194	4.4859	**0.9%**	**-4.1%**
P4	2.5940	4.4208	**1.9%**	**-1.7%**

Key Takeaways:

- ***P1 project mitigates slightly more risk across the possible network upgrades***
- ***Cheapest option across the four projects considered***
- ***From a cost-benefit perspective, P1 presents the largest NPV to meet system needs and mitigate risk due to a HILF event***

Key Takeaways

- Risk-based approaches provide
  - A significantly more comprehensive analysis of system reliability
  - Better means of balancing cost and acceptable level of reliability and resiliency
- The methods are gaining more attention due to significant changes in power systems and as planners realize the limitations of deterministic view of the system

- Risk-based methods are
  - Data and computationally intense
  - Developing a large number of power flow cases with ac feasible solution is challenging
  - A large number of contingencies can diverge rendering the results difficult to interpret
  - Tools are not standardized
  - Planners are not familiar with the approaches yet
  - No standard indices/benchmarks; no defined planning standards

Although are not ready for full adoption, risk-based approaches can certainly augment the existing deterministic transmission planning process and provide deeper understanding of issues to balance cost and transmission reliability/resiliency

MI POWER GRID

Making the Most of Michigan's Energy Future

Break

Please mute your microphone and turn off your camera during break.

MI POWER GRID

Making the Most of Michigan's Energy Future

Transmission Planning and IRP

Farah Mandich and Drew Siebenaler

Xcel Energy

MPSC

Michigan Public Service Commission

Like Peanut Butter & Jelly: Resource and Transmission Planning at Xcel Energy

Presentation to MI Power Grid

January 19, 2021

Intro to Xcel Energy and relevant planning processes

- Upper Midwest service area includes ~1.8 million electric customers in five states*

- Company-wide commitment to carbon reduction:
  - 80% below 2005 levels by 2030
  - 100% carbon free electricity by 2050

Planning Processes

- Upper Midwest system Resource Planning
  - File in MN, MI; informational in other states
- Minnesota utilities' biennial transmission planning
- MISO regional transmission planning

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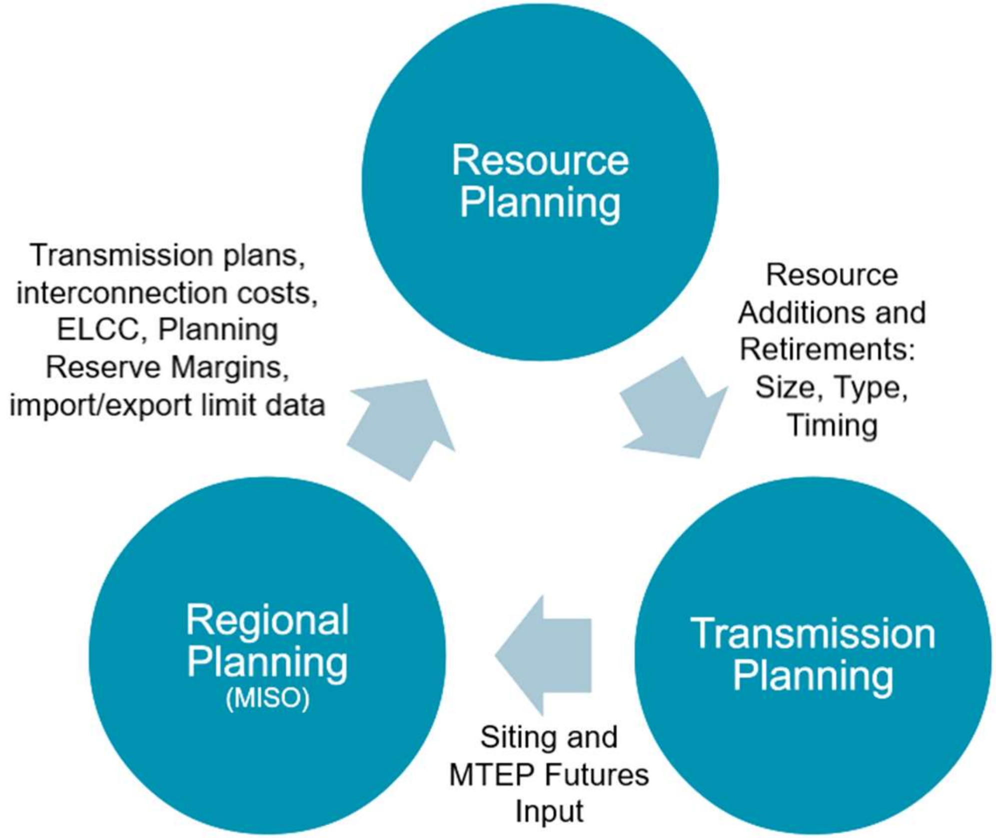
* Across all service areas, Xcel Energy serves approximately 3.7 million electric and 2.1 million gas customers in 8 states

Resource planning and transmission planning inform each other

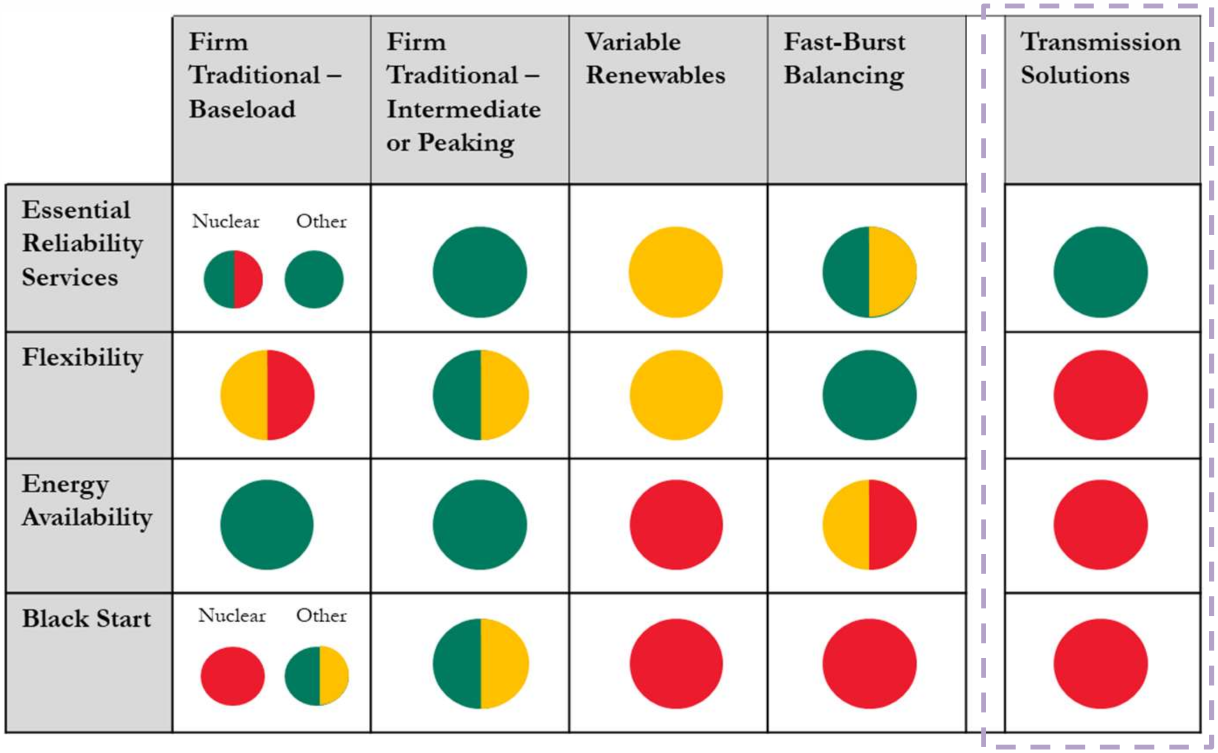


Key interfaces between processes

- Inputs and outputs are **interdependent**
- Process is **iterative**
- **Portfolio level** estimates considered in **IRP**
- **Specific solutions** considered in **transmission planning** or coordinated analyses

Resource attributes considerations bridge resource and transmission planning

Resource attributes mapped to resource types



	Firm Traditional – Baseload	Firm Traditional – Intermediate or Peaking	Variable Renewables	Fast-Burst Balancing	Transmission Solutions
Essential Reliability Services	Nuclear 🟢🔴 Other 🟢	🟢	🟡	🟢🟡	🟢
Flexibility	🟡🔴	🟢🟡	🟡	🟢	🔴
Energy Availability	🟢	🟢	🔴	🟡🔴	🔴
Black Start	Nuclear 🔴 Other 🟢🟡	🟢🟡	🔴	🔴	🔴

- Transmission solutions:
  - **Enable** other resources
  - Provide **essential reliability services**
- Transmission planning **informs** these needs and site-specific issues in IRP

Specific transmission solutions studied iteratively, to inform IRP

Use of MISO Y2:

- Non-binding **resource retirement exploration**
- Transmission analysis **indicative thermal, voltage, stability** concerns
- **Informs evaluation** of generation replacement, transmission alternatives

Solution	Pros	Cons
Generation Replacement	▪ Maintains system "as-is" ▪ Continued energy production	▪ Limited optionality
Transmission Solutions	▪ Increased optionality	▪ No energy production ▪ Forfeits interconnection rights
NTA/Hybrid	▪ Potential synergy ▪ Balance of resource flexibility and function	▪ Partial loss of rights ▪ Tailored solution limits use

NTA: Non-Transmission Alternatives

Going forward, we continue to integrate processes and increase collaboration

- **Internal culture and communication**
  - From transactional to ongoing, strategic communication

- **Analytics and planning**
  - Incorporate more transmission-related factors into IRP
  - Automating outputs from each planning process
  - Feedback into MISO processes

MI POWER GRID

Making the Most of Michigan's Energy Future

Transmission Owner Perspectives

MPSC

Michigan Public Service Commission

UP Energy Task Force

ATC's UP Transmission System

PRESENTED BY

Bob Morton
Heather Andrew

01/19/2021

AMERICAN TRANSMISSION COMPANY®

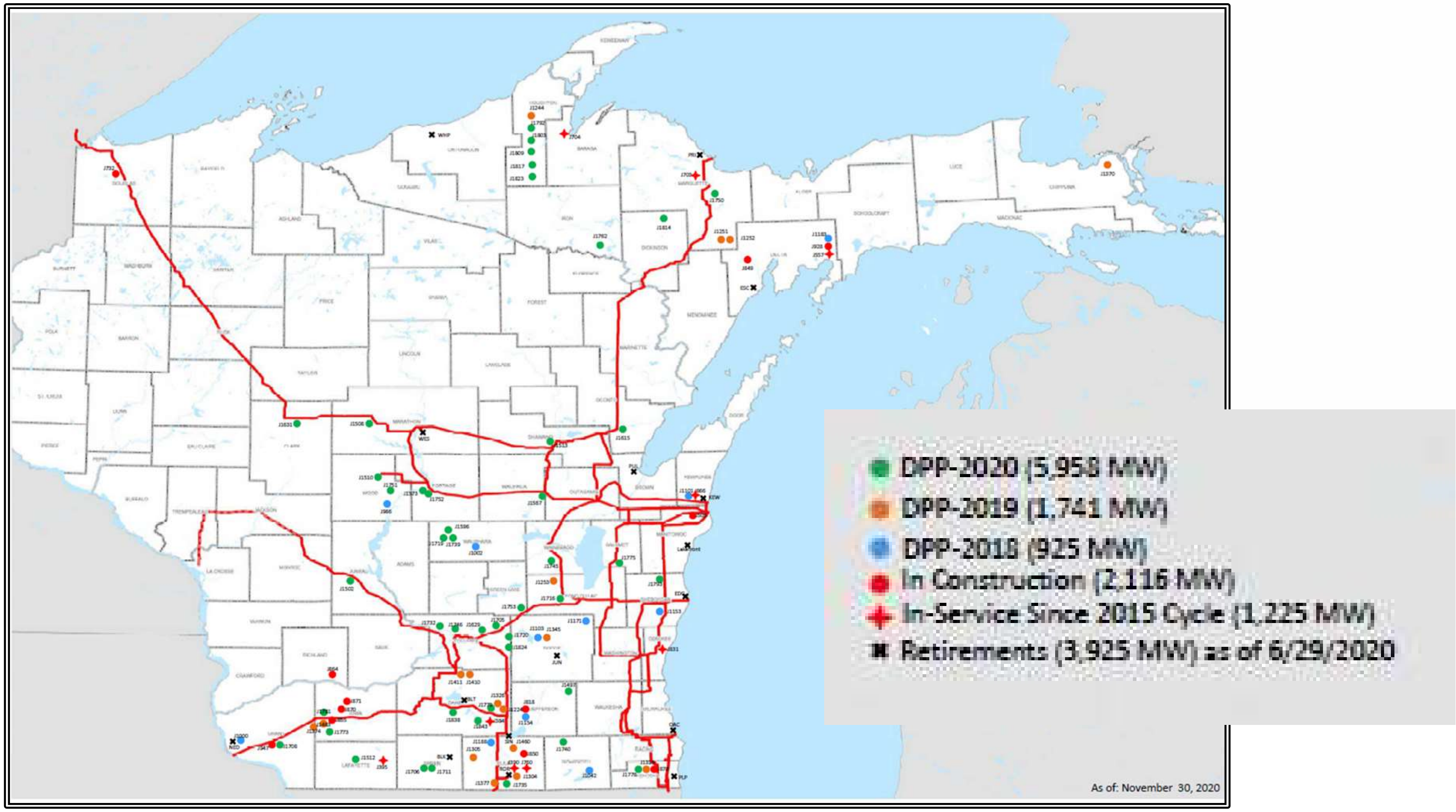
OUR VISION

Connecting you with
a sustainable energy future

Transmission Planning Coordination

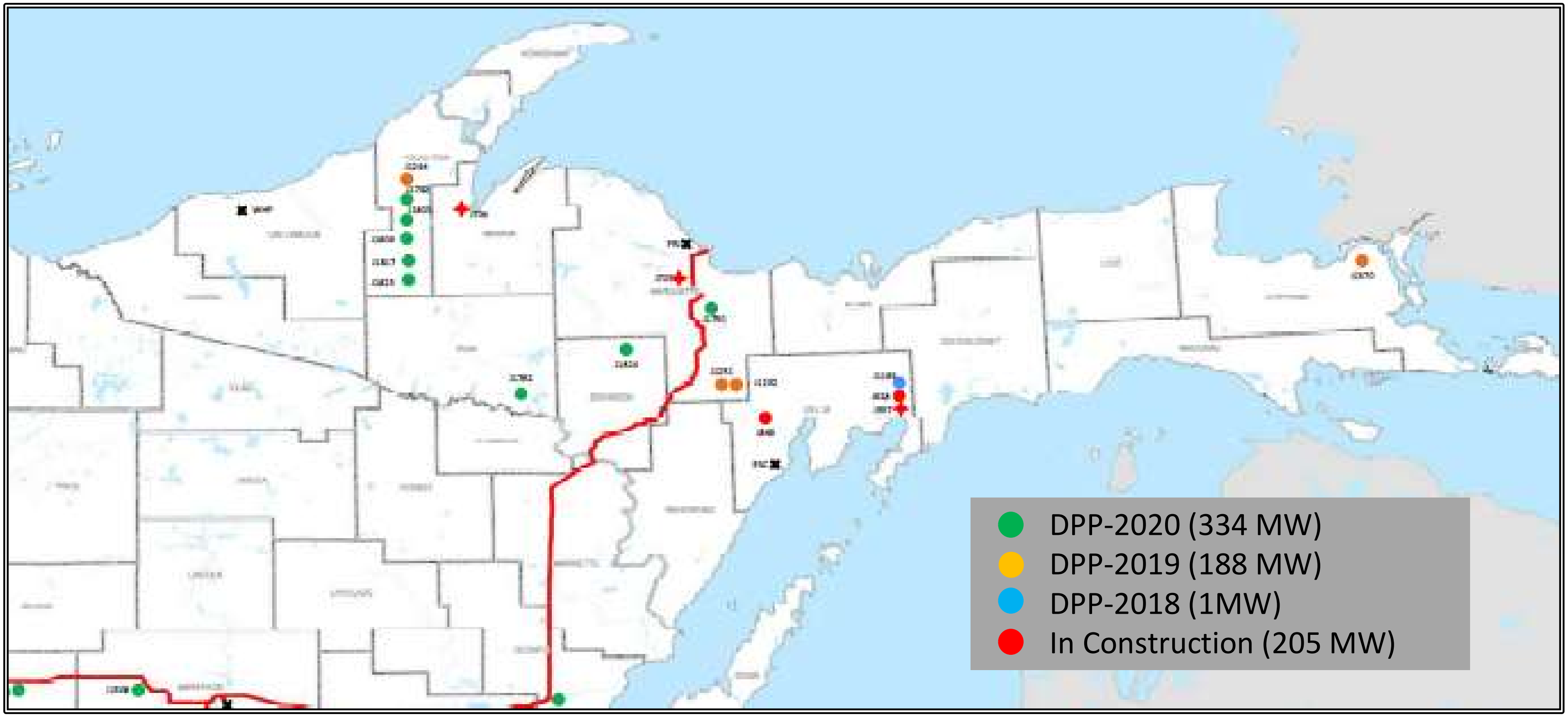
- Planning Coordination is Continuous with our Customers
  - Generation Owners
    - Additions
    - Modifications
    - Retirements
  - Distribution Providers
    - New Loads
    - Modifications
    - Distributed Energy Resources (DERs)
  - MISO Provides a Key Venue for both

Generation – MISO DPP Queues



As of: November 30, 2020

Upper Peninsula Generation



Coordination with Interconnected Entities

Multiple Planning Coordination Meetings

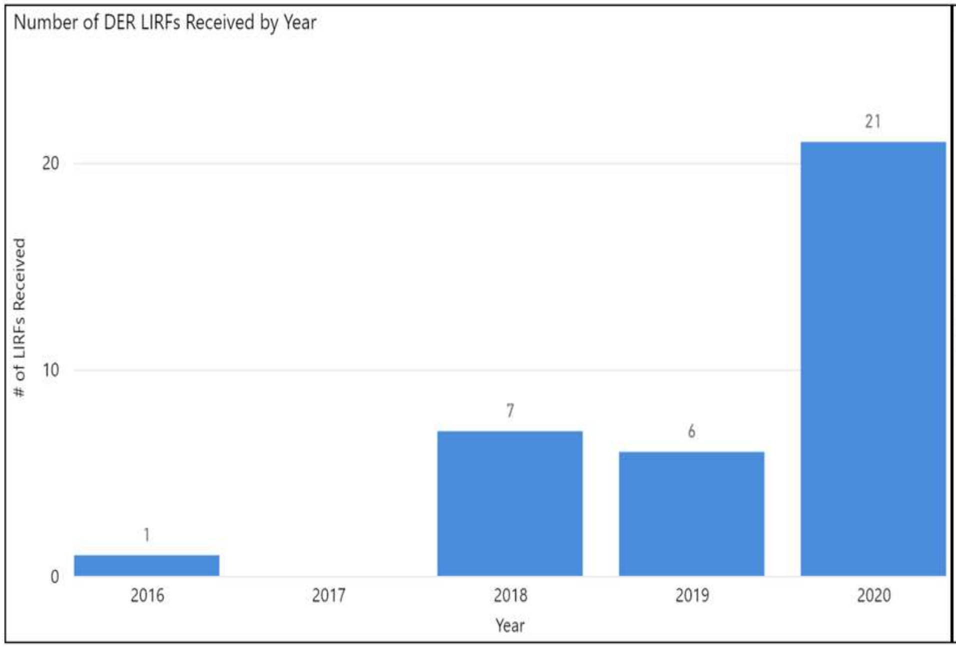
- Traditional Planner to Planner Coordination
- Emerging Issues with DERs

More Rigorous Modeling Requirement Details

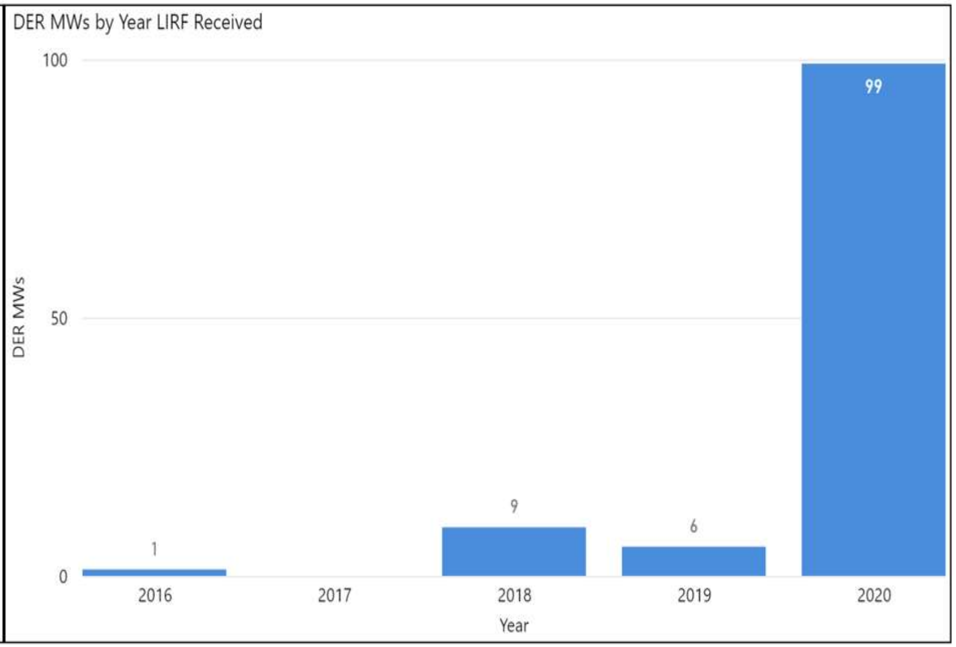
- MISO Model User Group
- NERC System Planning Impacts of DERs Working Group (SPIDERWG)

DER Trends

DER Requests Received by Year



DER MW's by Year Received



Adapting to Changing Requirements

Build on Existing Communications and Processes

IRPs are best integrated into existing regional processes

AMERICAN TRANSMISSION COMPANY®

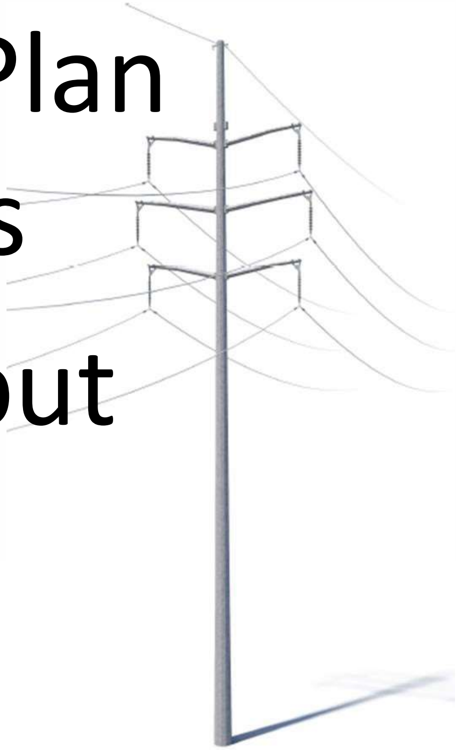
INDIANA
MICHIGAN
POWER

An AEP Company

BOUNDLESS ENERGY

Integrated Resource Plan (IRP) Process

and Transmission Input



January 19, 2021

INDIANA MICHIGAN POWER
An AEP Company
BOUNDLESS ENERGY

IRP Planning Process

- The IRP serves as a planning tool used to support future resource decisions to meet the capacity and energy needs of our customers in a cost effective manner.

- The IRP includes:
  - Robust stakeholder process
  - Economic evaluation of a diverse range of load and resource scenarios and assumptions

Transmission Planning Process

*https://www.aep.com/requiredpostings/AEPTransmissionStudies

Assumptions

- FERC 715*
- Connection Requirements*
- Guidelines for Transmission Owner Identified Needs*
- NERC/RTO

Needs Identification

- Consolidated asset and system needs
- Stakeholders engagement

1. Holistic needs shared at Regional Stakeholders Summit set up by AEP annually
2. PJM SRRTEP and TEAC Meetings

Portfolio Development

- Feasibility assessment of solutions for each region
- Document assumptions and alternates
- Complete submission documents

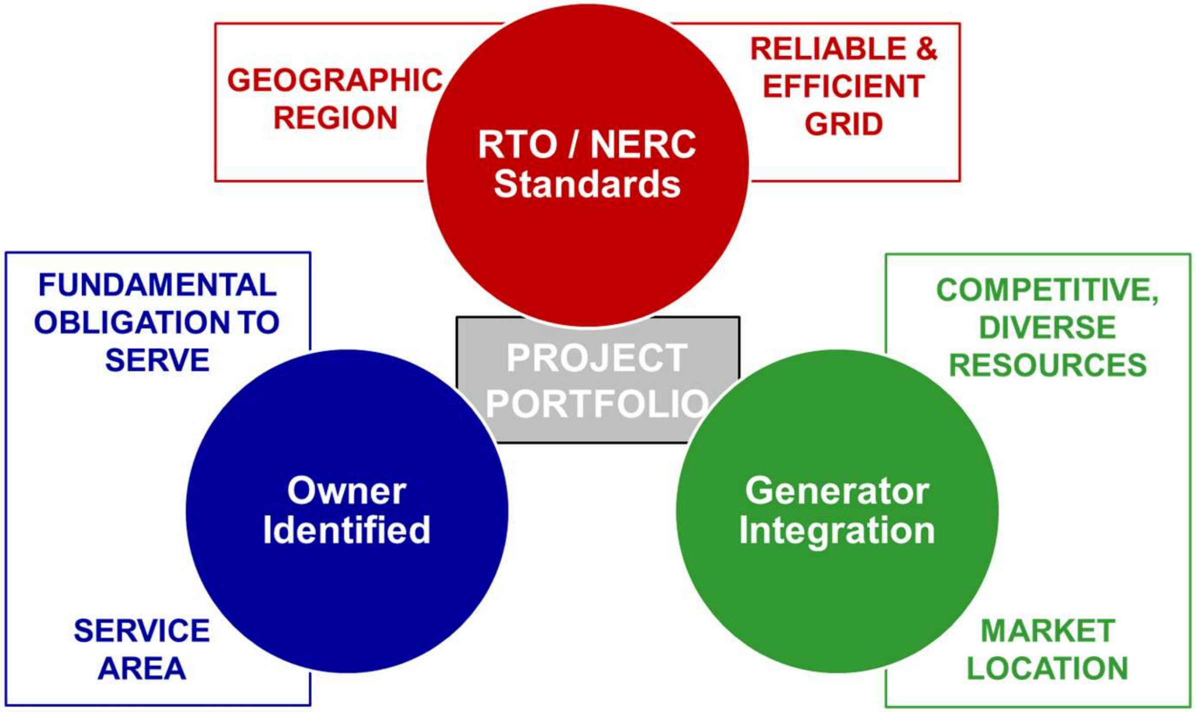
Projects Submissions & Approval

- Internal approval to secure funding and resources
- PJM stakeholder review

Projects Execution

- Engineering, Procurement and Siting
- Construction
- Project in-service

Transmission Project Drivers



GEOGRAPHIC REGION

RELIABLE & EFFICIENT GRID

RTO / NERC Standards

FUNDAMENTAL OBLIGATION TO SERVE

PROJECT PORTFOLIO

COMPETITIVE, DIVERSE RESOURCES

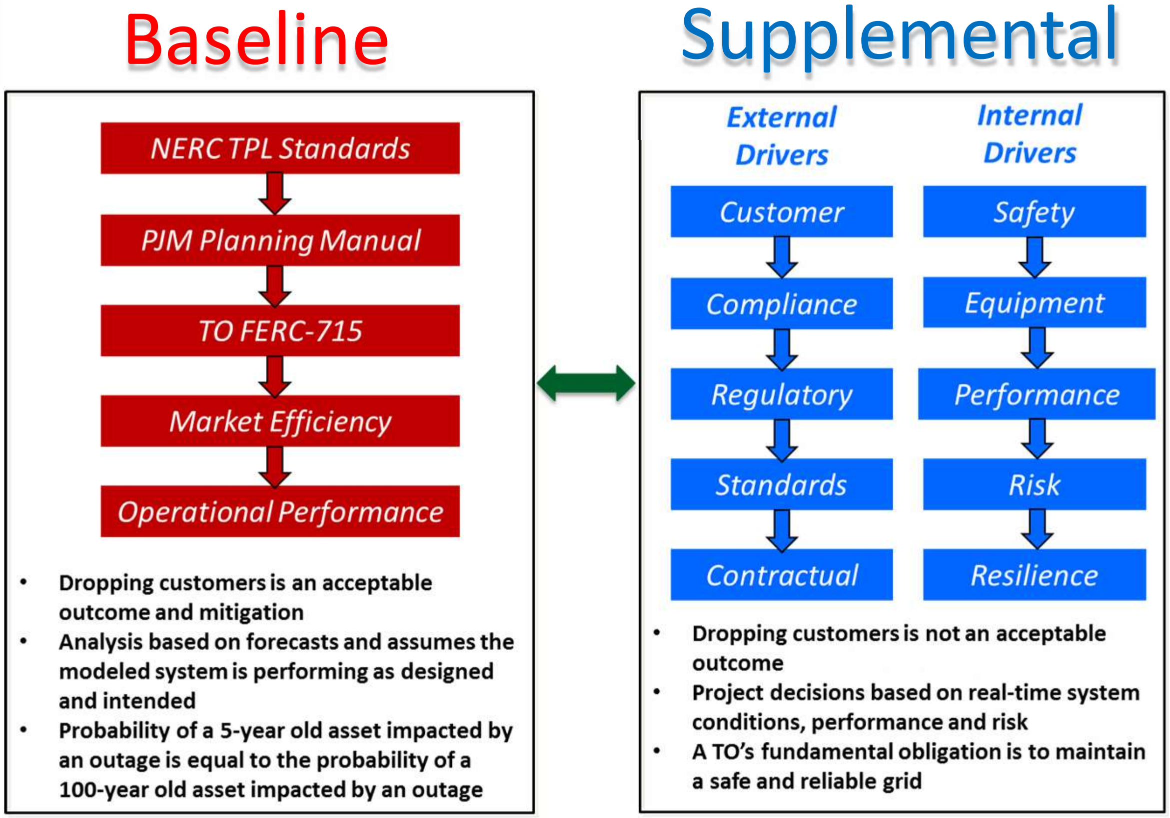
Owner Identified

Generator Integration

SERVICE AREA

MARKET LOCATION

Baseline vs. Supplemental



Baseline

- NERC TPL Standards
- PJM Planning Manual
- TO FERC-715
- Market Efficiency
- Operational Performance

- **Dropping customers is an acceptable outcome and mitigation**
- **Analysis based on forecasts and assumes the modeled system is performing as designed and intended**
- **Probability of a 5-year old asset impacted by an outage is equal to the probability of a 100-year old asset impacted by an outage**

Supplemental

External Drivers	Internal Drivers
Customer	Safety
Compliance	Equipment
Regulatory	Performance
Standards	Risk
Contractual	Resilience

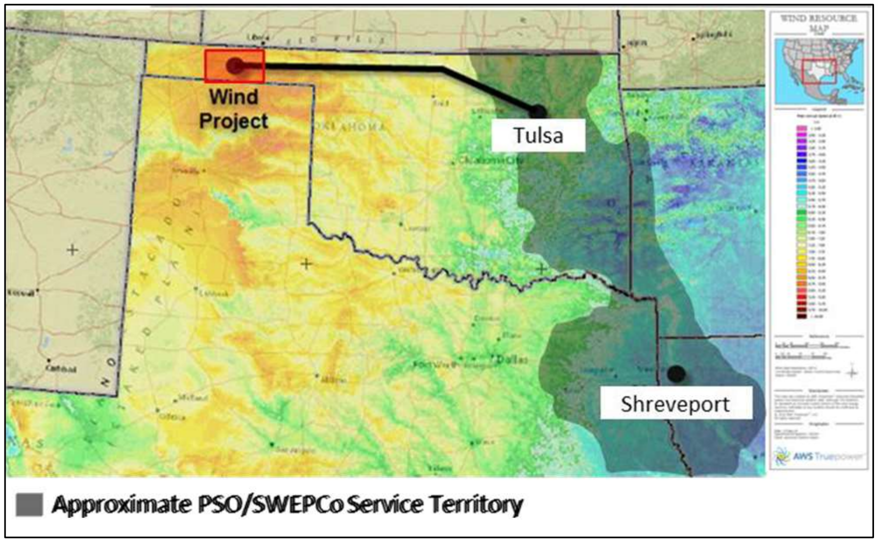
- **Dropping customers is not an acceptable outcome**
- **Project decisions based on real-time system conditions, performance and risk**
- **A TO's fundamental obligation is to maintain a safe and reliable grid**

Planning Collaboration

- In addition to the project specific meetings that include I&M stakeholders, additional planning meetings are held monthly to discuss overall project implementation
- Includes general review of any upcoming or new concepts of projects to ensure all needs are accounted for
- For example, general conversion plans for 34.5 kV system are discussed to ensure long term plans (>10 years out) are in alignment
- Capacity review meetings are held quarterly to review Distribution expansion needs
- All project approvals route through I&M President Toby Thomas

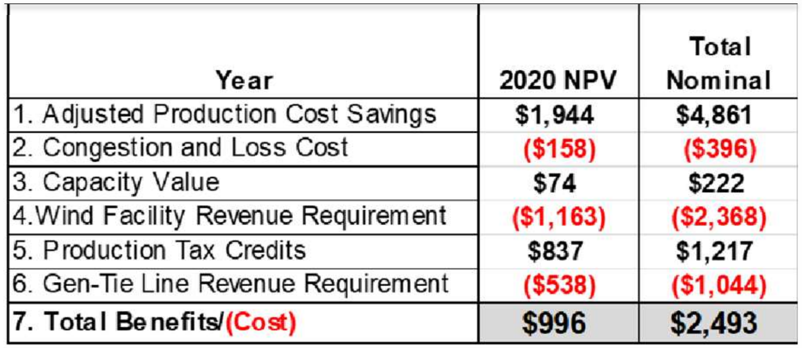
Wind Catcher

- Recommended ownership of up to 2,200 MW wind farm and a dedicated 350-mile generation tie line.
- The dedicated gen tie line was essential to ensure deliverability and was expected to provide benefits that are in excess of its cost.
- Net capacity factor of wind in western Oklahoma close to 55% compared to 45% (or less) near the load zone.



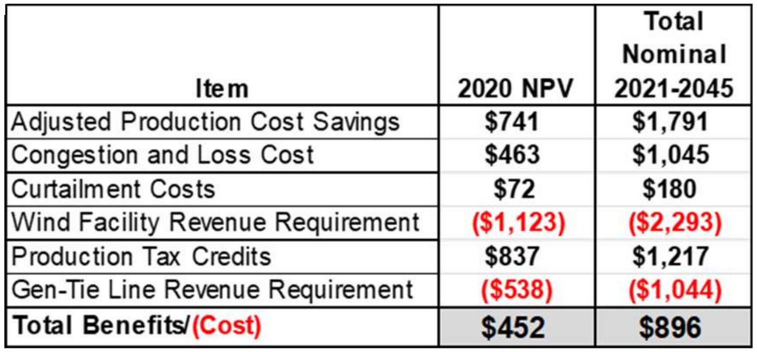
Benefits & Outcome

Wind Catcher



Year	2020 NPV	Total Nominal
1. Adjusted Production Cost Savings	$1,944	$4,861
2. Congestion and Loss Cost	($158)	($396)
3. Capacity Value	$74	$222
4.Wind Facility Revenue Requirement	($1,163)	($2,368)
5. Production Tax Credits	$837	$1,217
6. Gen-Tie Line Revenue Requirement	($538)	($1,044)
7. Total Benefits/(Cost)	**$996**	**$2,493**

Generic Wind without Tie-line



Item	2020 NPV	Total Nominal 2021-2045
Adjusted Production Cost Savings	$741	$1,791
Congestion and Loss Cost	$463	$1,045
Curtailment Costs	$72	$180
Wind Facility Revenue Requirement	($1,123)	($2,293)
Production Tax Credits	$837	$1,217
Gen-Tie Line Revenue Requirement	($538)	($1,044)
Total Benefits/(Cost)	**$452**	**$896**

- The Wind Catcher project was rejected by the Public Utility Commission of Texas (PUCT).
- It also met significant resistance in Oklahoma, especially pertaining to construction of the 350-mile generation tie-line due to right-of-way concerns.

2019 Southwest Power Pool Wind RFP (now known as North Central Wind)

- AEP affiliates Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO) issued an RFP to procure up to 2,200 MW of wind.
- A robust deliverability analysis was performed to ensure deliverability to the utilities' customers.
- A congestion cost analysis was performed to determine the risk of congestion and curtailment associated with each bid.
- PSO and SWEPCO recommended procurement of three projects totaling 1,485 MW due to risk of congestion and deliverability.
- Approved by state commissions in Arkansas, Louisiana and Oklahoma.

2020-2021RFP

- I&M issued RFPs on November 5, 2020 with proposals due by January 15, 2021.
- RFP is open to resources within Indiana and Michigan and/or resources connected to AEP's grid in MISO and PJM Regional Transmission Organizations (RTOs).
- Deliverability and congestion analysis will be performed to support the selection of resources.
- Transmission solutions will be considered.

Transmission Owner Perspectives

MI Power Grid Stakeholder Session

January 19, 2021

ITC | FOR THE GREATER GRID

MANY STAKEHOLDERS, ONE GOAL

ITC MICHIGAN

ITC*Transmission* & **Michigan Electric Transmission Company** (METC)

- ~8,700 miles of line serving Lower Peninsula
- 120kV - 345kV range
- Top-tier system reliability
- ~570 Employees

THE LANDSCAPE

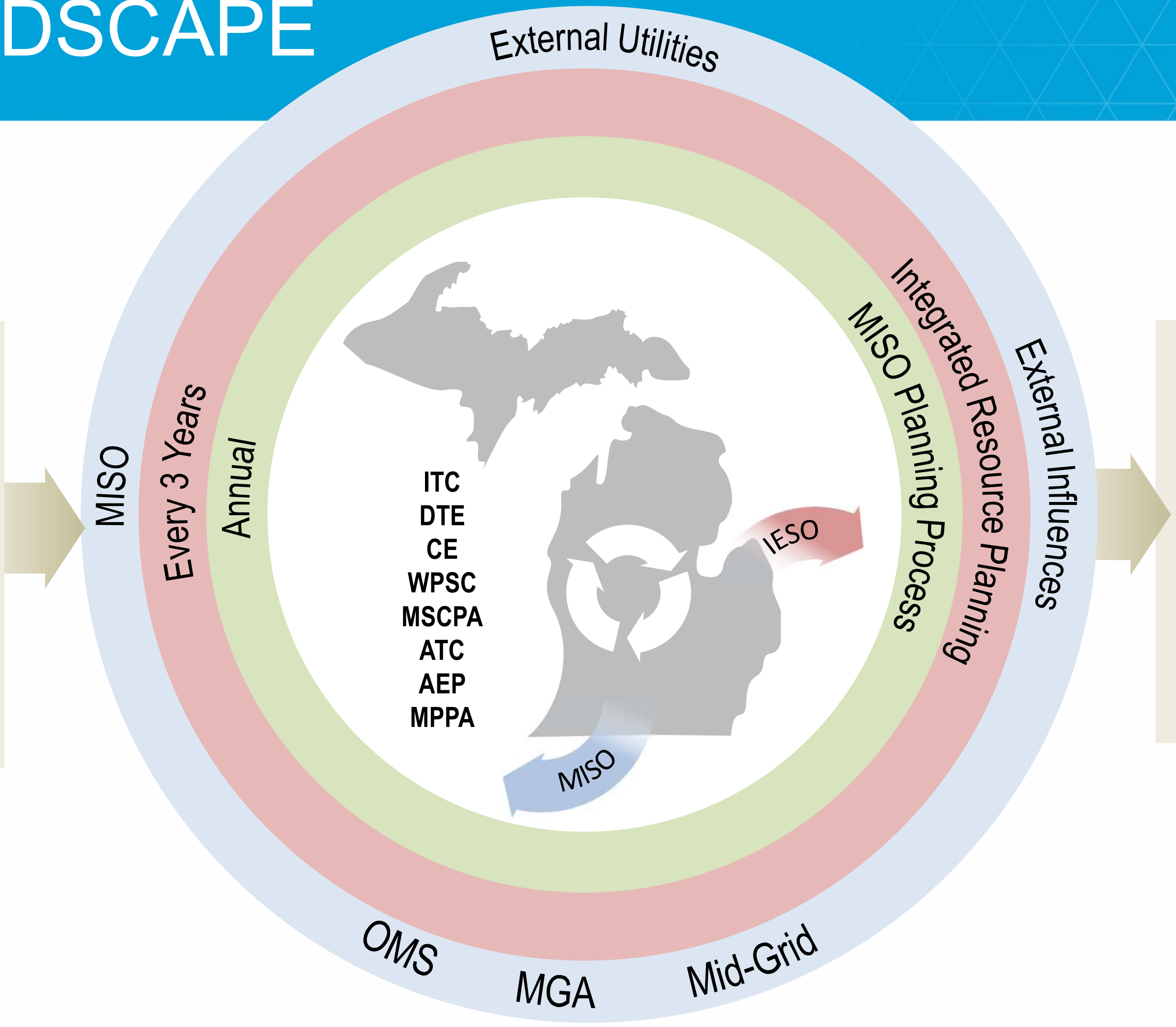
INFLUENCES / ISSUES

Policy goals

Resource adequacy

RIIA

Load



SOLUTIONS

MISO MTEP

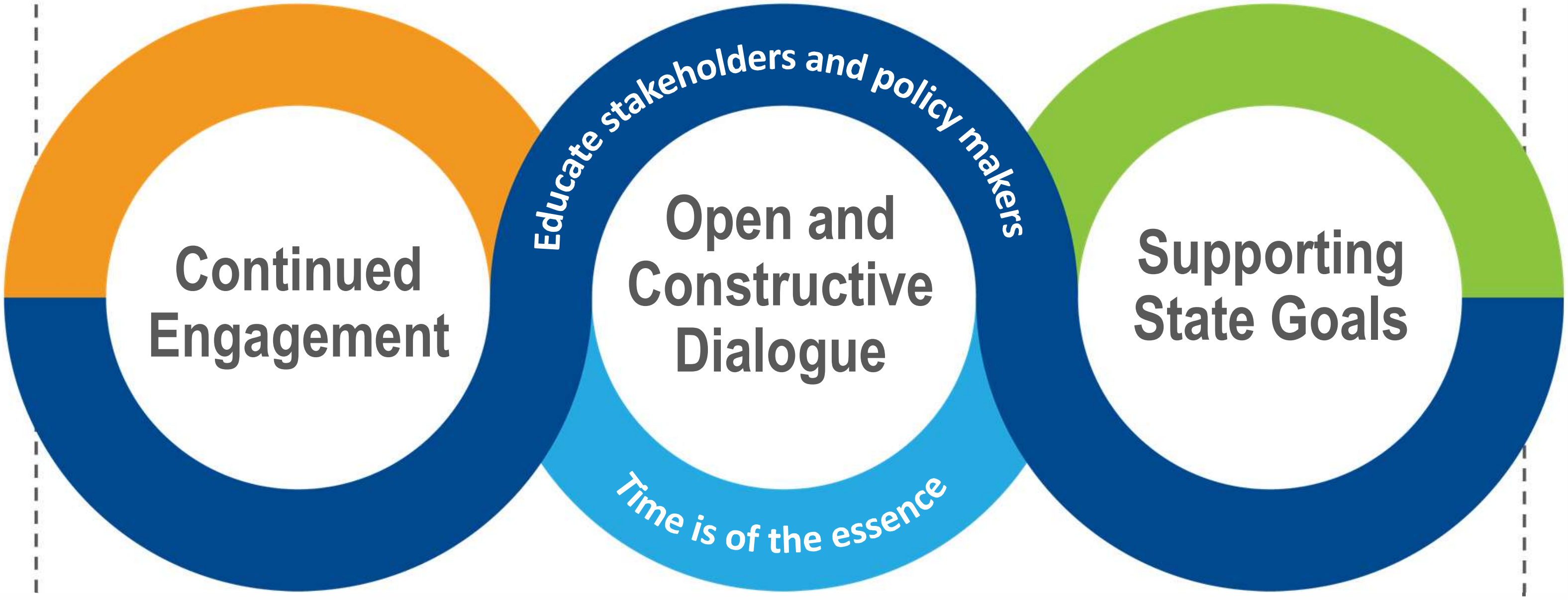
Long-range planning

FIVE FACTORS FOR IRP SUCCESS

1. Analyze location of generation resources
2. Screen transmission options against other resource options
3. Hold meetings three months prior to filing
4. Assess the full value of transmission
    - Reliability
    - Import capacity
    - Environmental benefits
5. Allow flexibility for study work

NEXT STEPS

Where do we go from here?



Continued Engagement

Open and Constructive Dialogue

Supporting State Goals

Educate stakeholders and policy makers

Time is of the essence

A FORTIS COMPANY™

Thank You

FOR THE
GREATER GRID

MI POWER GRID

Making the Most of Michigan's Energy Future

Discussion and Feedback Request

Zachary Heidemann

MPSC

Michigan Public Service Commission

MCL 460.6t (5) (h) & (j)

- An analysis of potential new or upgraded electric **transmission options** for the electric utility.

- Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any **transmission or distribution infrastructure** that would be required to support the proposed construction or investment, and power purchase agreements.

Stakeholder Discussion

- What should be considered a transmission option in the IRP?
- Who is responsible for identifying the transmission option?
- If the transmission option requires imported capacity and energy, how should that be identified and evaluated, and how are the costs compared to in zone resources?

Stakeholder Discussion

- MISO's MTEP process is generally evaluates transmission reliability, load and generation interconnection.
  - Should there be a way to communicate distribution level information to the transmission utility? When and how should this information be passed?
- Communication has often been highlighted through our stakeholder presentations. What should the expectation for communication outside of the RTO process between TOs and distribution utilities be? How often? What should the discussion include?
- Given the volatile nature of the CIL what is it the best measure of import capacity? What other measure would you suggest?

Current filing requirements

- In accordance with MCL 460.6t(5)(h), the utility shall include an analysis of potential new or upgraded electric transmission options for the utility. The utility's analysis shall include the following information:
  - a) The utility shall assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options;
  - b) A detailed description of the utility's efforts to engage local transmission owners in the utility's IRP process in an effort to inform the IRP process and assumptions, including a summary of meetings that have taken place;
  - c) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns;
  - d) Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system, including both generation retirements and new generation, subject to confidentiality provisions;
  - e) Any information provided by the transmission owner(s), including cost and timing, indicating potential transmission options that could impact the utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboring RTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources.

Stakeholder Discussion

- What should be changed within the transmission planning section of the filing requirement?
  - Are they not defined enough or is there ability to be interpreted a strength?
  - What isn't included that should be?
  - Should more documentation be required to support the filing? What would the documentation be?

Stakeholder Discussion

How should transmission constraints be modeled in an IRP?

a) How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?

b) Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?

c) How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information? How is this done in a way that doesn't create undue burden or an impossible task for utilities filing an IRP? Should out of state resources be allowed to enter RFPs provided they have firm transmission rights? Given the LCR has been a limiting agent in the last MISO year does it make sense to consider out of state resources?

MI POWER GRID

Making the Most of Michigan's Energy Future

Closing

Naomi Simpson

MPSC

Michigan Public Service Commission

Written Feedback Request

- What should be changed within the transmission planning section of the filing requirement?
  - Are there specific changes that stakeholders would recommend based upon the conversation today that would clarify, add, or change the existing filing requirements?
  - What documentation would stakeholders find helpful in the filing?

Written Feedback Request

How should transmission constraints be modeled in an IRP?

a) How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?

b) Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?

c) How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information? How is this done in a way that doesn't create undue burden or an impossible task for utilities filing an IRP? Should out of state resources be allowed to enter RFPs provided they have firm transmission rights? Given the LCR has been a limiting agent in the last MISO year does it make sense to consider out of state resources?

Written Feedback Request

We look forward to your written comments in response to Staff's feedback request. Your participation is critical.

Please submit responses to the stakeholder feedback comments received to Danielle Rogers by

February 1, 2021, 5pm ET.

RogersD8@michigan.gov

MI POWER GRID

Making the Most of Michigan's Energy Future

Thank You

Upcoming Advanced Planning Stakeholder Meetings
February 9, 2021 at 1:00 p.m. ET
March 2, 2021, time TBD