TRANSMISSION CONNECTION FEES AND PRINCIPLES OF COST ALLOCATIONS

NARUC ENERGY REGULATORY PARTNERSHIP WITH GEORGIAN NATIONAL ENERGY AND WATER SUPPLY REGULATORY COMMISSION & MICHIGAN PUBLIC SERVICE COMMISSION

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FERC Orders Establishing USA Transmission Policy

- Order 888 – No Planning Requirement for ISOs
- Order 2000 – Planning Requirement for RTOs
- Initially, RTOs addressed Reliability, then Economic Planning and cost allocation issues
- Order 890 – Planning Requirement for all Transmission Providers, including ISO/RTOs

 - Requires both Reliability & Economic Planning

 - Requires cost allocation to be developed for each region, and each region developed different cost allocation methodologies

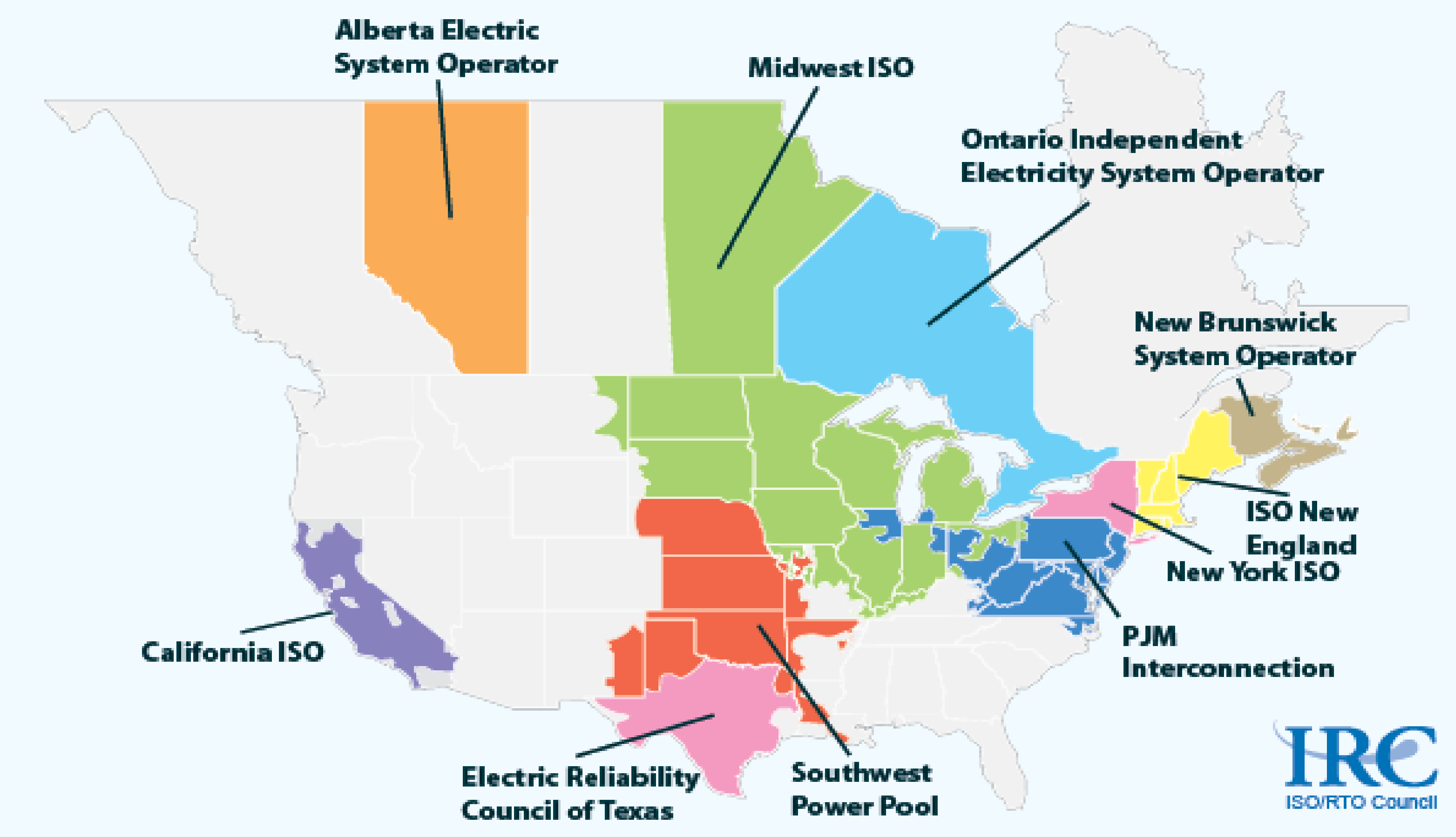
 - Requires inter-regional coordination

 - All ISO/RTO Order 890 Planning Processes have now been accepted by the Commission

FERC Foundation of Establishing ISOs and RTOs

- 1997 FERC Orders 888, began the deregulation of the traditional utility
- Additional FERC Orders 2000 and 1000 established the foundation for transmission cost allocation
- FERC began to set up the concept of ISOs which allowed third parties to manage functions of the electric grid that were traditionally the responsibilities of the vertically integrated utilities (Generation, Distribution, and Transmission)
- FERC later established RTOs to operate multi-state transmission projects
- FERC regulates rates, complaints, tariffs of MISO and TOs

North America ISOs and RTOs



ISOs and RTOs

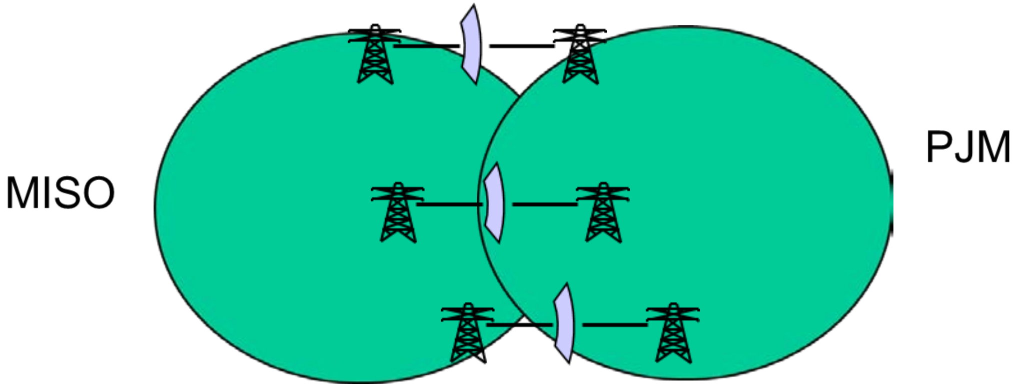
- RTO—Regional Transmission Operator
  - PJM & MISO www.miso-pjm.com
  - MISO www.misoenergy.org
  - PJM www.pjm.com
- Regional State Entities
  - OMS www.misostates.org
  - OPSI www.opsi.us
- Independent System Operators
  - California ISO www.casio.com
  - New York ISO www.nyiso.com

Regional Transmission Operators

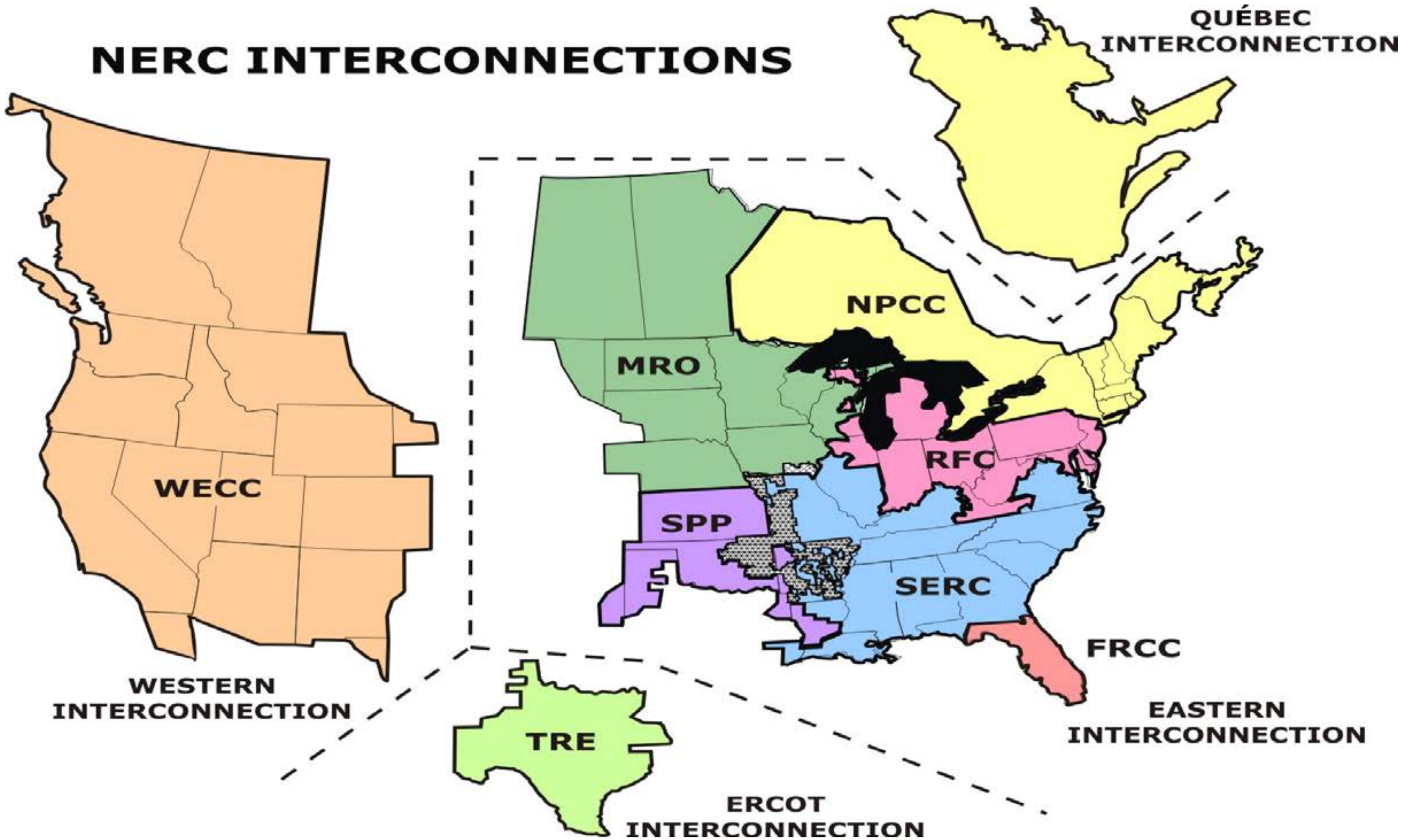
- Midwest Independent System Operator **(MISO)**
- PJM Interconnection **(PJM)**
- Responsible for delivery of safe cost effective electric power
- Oversee the flow of power over the high voltage wholesale transmission system
- Provide independent wholesale transmission system access
- Manage power congestion
- Coordinate reliability
- Plan regional transmission system
- Operate day –ahead and real –time energy and ancillary services markets. PJM operates capacity market; MISO operates small capacity market auction for entities short on capacity in 2005
- Act as balancing authorities and doing this all since 1998

Continued Coordination Between RTO Markets Can Create Joint/Common Market

1. PJM & MISO coordinate flows between them
2. MISO responsible for redispatch for some PJM flowgates affected more by MISO generation and flows and vice versa.
3. PJM & MISO exchange data on constraints, bids LMP prices
4. PJM & MISO readjust their dispatches and then exchange data again, etc…
5. Both RTO's run numerous iterations to optimize inter-regional dispatches and prices
6. These iterations form the basis for a joint/common market yielding one unified economic dispatch



NERC Areas of Interconnections



NERC Foundation and Authority

- NERC was established by the electric utility industry in response to the 1965 blackout.
- NERC was formed on June 1, 1968, by the electric utility industry to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America, and continues to be their mission.
- As part of the fallout of the Northeast Blackout of 2003, the Energy Policy Act of 2005 authorized FERC to designate a national Electric Reliability Organization (ERO) with NERC becoming the ERO in July 2006. Changing its policies into standards with enforcement.
- NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the US, Canada, and two portions in Mexico south of California and New Mexico.
- NERC's major responsibilities include working with all stakeholders to develop mandatory standards for power system operation, monitoring and enforcing compliance and issuing fines with those standards, assessing resource adequacy, and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient.
- NERC also investigates and analyzes the causes of significant power system disturbances in order to help prevent future events

NERC Planning Coordinator Role

- Establish Standards for:
- Transmission Planning (TPLs)
- Facilities (FACs)
- Modeling (MODs)
- Nuclear (NUC)

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TRANSMISSION COMPANIES MUST CONFORM TO:

- Federal Standards for providing safe and reliable power
- Federal Standards
  - NERC-North American Electric Reliability Corporation
  - NESC-National Electrical Safety Code
- Federal Energy Regulatory Commission
  - Order 888, 889,890
  - Order 1000
  - Order 2000

Projects Must Satisfy Three Foundational Requirements

- **Reliability**
  - NERC contingencies
  - Voltage and thermal supports "Keep the lights on"
  - Generation Retirements or Interconnections
  - Transmission Service Requests
- **Economic**
  - Minimum Total Cost—energy, capacity, transmission
  - Minimize costs to all end users
  - Market Congestion Planning –specific flow gates
- **Public Policy**
  - Integrate the laws, regulations, statues, mandates into planning in the most cost effective and reliable manner
  - Renewables, security, safety
  - Dictated by the regulators, and combination of reliability and economics

Inputs to Long term Planning

INPUTS

- Demand and Energy
- Resource Mix
- Location of Load and of Generation (Resources)
- Transmission System
- Policy
- Stakeholder (public or Commission) review

Process Planning

1. Resource Forecast—regional, national, international
2. Site Generation—where its needed and model in powerflow
3. Design Conceptual transmission overlays
4. Test conceptual transmission for robustness
5. Consolidate and sequence transmission plans
6. Evaluate conceptual transmission for reliability
7. Run Cost Allocation Analysis
8. Using various Planning Models (Tools)

Outputs to Long Term Planning

OUTPUTS

- Identify solutions that provide:
  - o Reliability
  - o Economic and
  - o Public Policy Benefits

Each input or process provides different information that is required for a comprehensive planning approach and appropriate results with the ultimate goal of the minimum total cost of energy, capacity and transmission.

Transmission Cost Allocation

- The Central Question: Who Pays? Why it Matters
- Objectives of Cost Allocation – Guiding Principles
- Building Blocks for Allocating Transmission Costs
- Cost Allocation Methods – An Overview
- Examples of Cost Allocation Approaches Used-MISO
- Implementation Issues for Cost Allocation

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The Central Question: Who Pays? Why it Matters

- Cost allocation is all about determining **“who pays”**
- The willingness and ability to pay for transmission must exist for transmission plans to become a reality
- Cost allocation decisions have profound effects on:
- Rates paid by customers and access, affordability, efficiency
- The location and type of generation that is built and operates
- Economic development, growth and regional trade/linkages
- Environmental outcomes: carbon emissions, land use impacts, natural resource impacts, and human health

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Objectives of Cost Allocation – Guiding Principles

- Rates should be reflective of “cost causation”
- Cost causation considers both burdens and benefits
- Practical considerations for cost allocation methods
  - –Degree of precision (location, type of service, time period)
  - –Administrative ease: data requirements and procedures
  - –Understandability and public acceptance as “fair”
  - –Resilience: ability to reflect system changes over time
  - –Stability of rates and predictability for customer decisions
  - –Consistency with energy market policies, incentives, and planning

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"Beneficiary Pays" vs. "Socialization"

- Beneficiary Pays – only the parties that benefit from transmission projects should pay for them ("benefit" also means reducing the risk of unreliable service)
- Socialization – transmission benefits are inherently widespread and not easily assigned to local areas; therefore costs should be spread broadly across the system

“Beneficiary Pays” vs.“Socialization” (con’t)

The terms convey opposing cost allocation views:

- *Beneficiary Pays advocates*: “We can determine who causes costs/experiences benefits, and should assign the costs to them – not to others”

- *Socialization advocates:* “Transmission produces broad benefits for everyone, even if they are difficult to measure”

Building Blocks for Allocating Transmission Costs

- Total cost of service (revenue requirements)
- Customer load data (energy used, peak loads)
- Transmission planning outputs (if beneficiary pays methods are use)

– Market simulation tool (production cost model) to examine changes in in production costs, congestion, prices, and reliability

– Power flow models provide a basis for identifying the location of uses of the transmission system that can cause problems (thermal and voltage violations) that require solutions or new investment

Other ways to evaluate cost allocation methods may include

- Understandability
- Administrative ease
- Ability to reflect system changes over time
- The stability of rates stemming from the cost allocation method used to recover transmission costs
- Short-term and long-term incentives for generation and load
- Recognition of the public good and positive externality aspects of transmission infrastructure

Cost Allocation Methods – An Overview of Choices

- Allocating costs to load or generation, or both?
- Allocating costs based on megawatt-hours (MWh) or MWs? (both socialization methods)
- Allocating costs using location-based or flow-based methods (beneficiary pays method)
- Allocating costs using monetary benefits and the parties that obtain them from transmission projects (beneficiary pays method)
- Allocating costs across the entire RTO footprint (socialization method)

Transmission Project Types for MISO

- Baseline Reliability Project (BRP)
- Generation Interconnection Projects (GIP)
- Market Efficiency Project (MEP)
- Multi-Value Project (MVP)
- Participant Funded or “Other”
- Transmission Delivery Service

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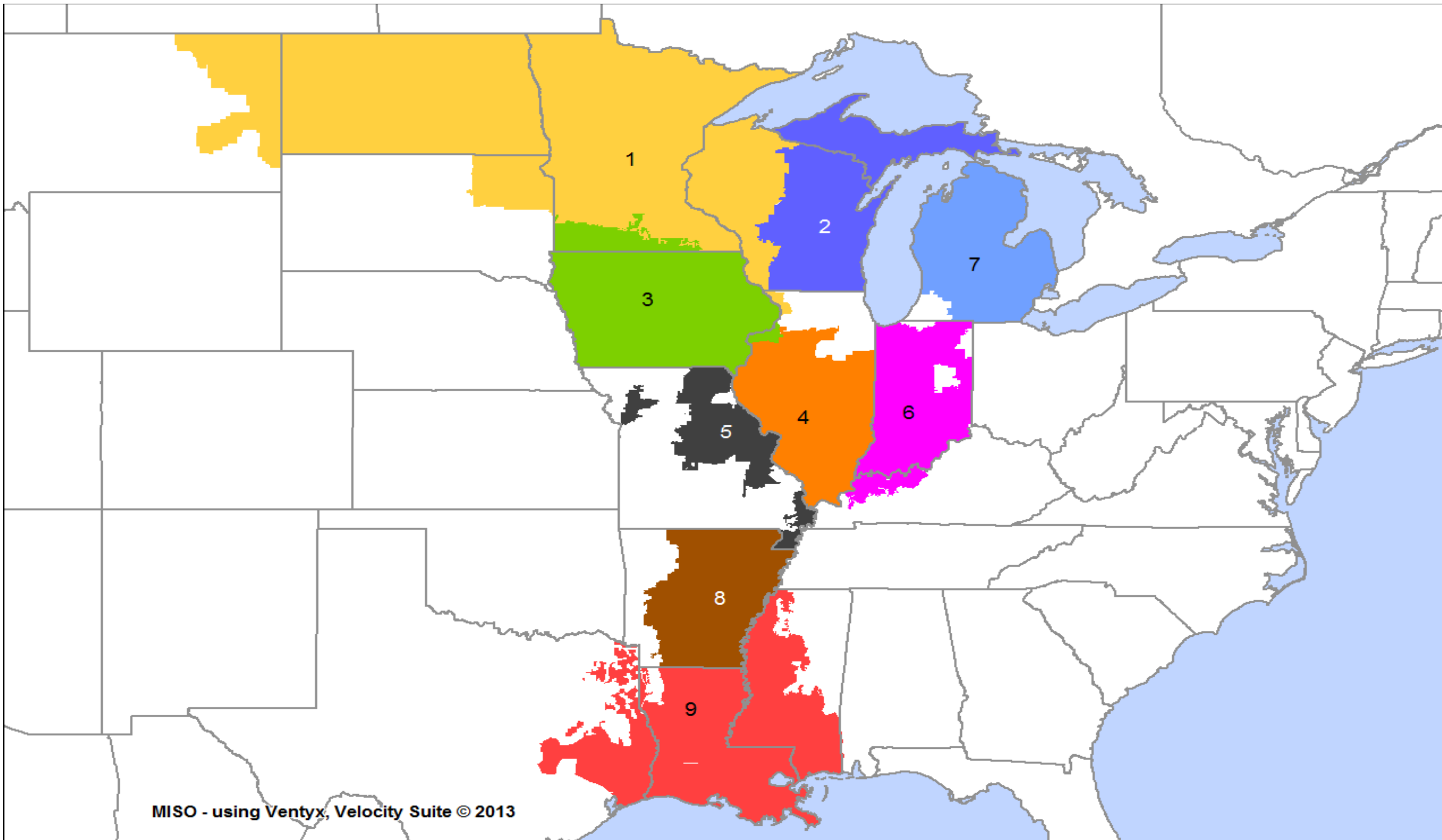
MISO's local resource zones (LRZs)



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Baseline Reliability Projects

- These projects ensure the system is reliable and in compliance with the applicable standards
- One big driver is the NERC Reliability Criteria (TPL standards) (thermal and voltage issues, and also local reliability issues)
- Costs are allocated in the local zone
- For example a transmission line built in Zone 7 will be allocated to only Zone 7 customers

http://www.nerc.com/files/TPL-001-4.pdf

NERC TPL-001-4 Table 1 Event Descriptions

New /Old Category /Description

New /Old Category	Description
P0 Cat A	System intact
P1 Cat B	Single contingency (Fault of a shunt device- fixed, switched or SVC/STATCOM is new)
P2 Cat C1, C2	Single event which may result in multiple element outage. Open line w/o fault, bus section fault, internal breaker fault
P3 Cat C3	Loss of generator unit followed by system adjustments + P1 (No load shed is allowed)
P4 Cat C	Fault + stuck breaker events
P5 (new)	Fault + relay failure to operate (new)
P6 Cat C3	Two overlapping singles (not generator)
P7 Cat C5, C4	Common tower outages; loss of bipolar DC

Generation Interconnection Projects

- Generator requests an interconnection with a transmission owner which can be a reliable and efficient transfer of power
- No minimum project cost requirement and any initial study costs are eligible for sharing
- Prior to construction the Generator funds 100% of network upgrades
- Shared Network Upgrades

– Allows first-movers to recover costs from later generators who benefit from their existing Network Upgrades

– Identification based on physical location of interconnection point or flow-based screening criteria to measure impact on eligible upgrades

– Eligibility for refund limited to five years after in-service date

Generation Interconnection Projects (cont)

- Upon Commercial Operation, the TO will repay 10% of the costs to Generator if Network Upgrades are 345 kV and higher
- For network upgrade projects under 345 kV, costs are primarily paid by the generator, however for the transmission owners in Michigan, the TOs (ATC, ITC, METC) reimburse the generator for the costs and then allocate the costs to the TO's customers
- For network upgrade projects greater than 345 kV, the generator pays 90% with the remaining 10% shared system-wide based on load ratio share

Market Efficiency Projects

- Network upgrade transmission projects that are shown to have regional economic benefits as projected through multi-year planning (5,10, 20 years) and multi-future scenarios
- Projects must reduce market congestion wherein the benefits are 1.25 times in excess of the cost with annual benefits calculated using 100% actual adjusted projected costs savings for multiple future scenarios
- The adjusted production cost is equal to the total production cost of the generation fleet adjusted for import costs and export revenue “Savings” for each future scenario is the difference between two cases: 1) base case without the project; and 2) case with the project

Market Efficiency Projects (cont.)

- Present value of benefits and costs calculated over the first 20 years after in-service date, but not to exceed 25 years from the project's approval year
- Projects restrictions are that must be facilities must operate at 345 kV or higher and be above $5 million in costs with 50% of the network upgrades be above 345 kV associated facilities
- Projected costs are allocated 80% to the local resource zone (load ratio share within each LRZ is used to allocate within each pricing zone) based upon the distribution of benefits and 20% system wide based on load ratio share
- "No Loss" provision prohibits allocation of the 80% component to LRZs that do not see benefits from project

Multi-Value Projects

- Projects that develop a regional transmission solution that provides economic, public policy and reliability benefits
- Projects must meet one of three criteria definitions in MISO's tariff in Attachment FF and have facilities serving >100 kV
- These projects address the energy policy laws of the states and US and/or provide widespread benefits across the footprint
- Must be evaluated as part of a portfolio of projects, as designated in the MISO transmission expansion planning process, whose benefits are spread broadly across the footprint, and approved by MISO's Board of Directors

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Multi-Value Projects (cont)

- Must have a project cost greater than or equal to the lesser of: 1) $20 million or 2) 5% of the constructing TO's net transmission plant as defined in Attachment O
- Costs are allocated 100% postage stamp to load across MISO's footprint—socialized costs
- Projects examples are wind farms that did not have big transmission lines nearby but are in high wind producing areas, so need to build to get the wind to where the customers
- 100% of the annual revenue requirements for MVP are allocated on a system-wide basis to Transmission Customers that withdraw energy from the MISO system including export and through transactions sinking outside the MISO region (excluding PJM), and recovered through an MVP Charge

Multi-Value Projects (cont)

- Should a project qualify as a MVP and also qualify as either a BRP, MEP, or both, the project will be designated as a MVP and not as a BRP or MEP
- Any Network Upgrade cost associated with constructing an underground or underwater transmission line above and beyond the cost of a feasible alternative overhead transmission line providing comparable regional benefits will not qualify for cost sharing
- Any DC transmission line and associated terminal equipment will not qualify for cost sharing if the scheduling and dispatch of the DC transmission line is not turned over to the MISO markets, real-time control of the DC transmission line is not turned over to the MISO automatic generation control system and/or the DC transmission line is operated in a manner that requires specific users to subscribe for DC transmission service

Project Type Hierarchy

- **Cost shared as a:**
  - Multi Value Project
    - If is also qualifies as a BRP and/or a MEP
  - Market Efficiency Project
    - If it also qualifies as a BRP but not as a MVP
  - Baseline Reliability Project
    - If it does not also qualify as a MEP or MVP
  - Generation Interconnection Project
    - If it does not also qualify as a BRP, MEP, or MVP

Participant Funded or Other Projects

- Transmission Owner identified project that does not qualify for other cost allocation mechanisms
- Costs are paid by the requestor in the local pricing zone using by that TO's customers
- Example projects are new lines and substations to an LNG plant, hockey arena, replacement of old poles, lines, etc…

Transmission Delivery Service Projects

- Specific transmission service request projects by a TO or a customer
- Costs are generally paid by the TO customer
- TO can elect to roll-in costs into local pricing zone rates
- Examples are : wind farms connecting at the distribution level, specific distribution utility or larger customer requests

Calculating Annual Revenue Requirements for Cost Shared Transmission

- Transmission Owner (TO) provided information via FERC Form 1 Annual Reports
  - All TOs submit Attachment (ATT) O data
  - Submitted either by May 1 for historic TO's Cost of Service (COS) or December 1 for forward looking TO's COS
  - TO's ATT O Revenue Requirement (RR) to determine Schedule 7, 8, and 9 rates are adjusted based on ATT GG (BRP (prior to 2013), GIP, MEP) and MM (MVP) RR amount calculated to avoid over-recovery
  - TOs that have eligible cost shared projects submit ATT GG template for BRP, GIP, and MEP, or ATT MM template for Multi Value Projects
    - Necessary information to complete ATT GG/MM comes from ATT O and the "MTEP Project Completion" template
    - ATT GG/MM is used to calculate the Annual RR for eligible cost shared projects
    - TOs that have received FERC approval for Construction Work In Progress (CWIP) can submit RR for recovery prior to a project being in-service
      - Methodology to calculate Annual RR is similar for ATT GG (BRP, GIP, MEP) and ATT MM (Multi Value Projects)

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Overview of Attachment GG Annual Revenue Requirement Calculation

- Applies to all non-MVP cost shared project types
  - Annual Allocation factors are calculated for each of the following cost of service elements based on the current cost structure for the entire Transmission Owner system:
    - – Operation and Maintenance Expense (based on Gross Transmission Plant) includes Transmission O&M and Administrative & General Expenses
    - – General and Common Depreciation Expense (based on Gross Transmission Plant) examples include office buildings, computers, etc…
    - – Taxes Other than Income Taxes (based on Gross Transmission Plant) examples include payroll and property taxes
    - – Income Taxes (based on Net Transmission Plant) Federal and State Income Taxes
    - – Return on Rate Base (based on Net Transmission Plant) Rate of Return based on the Weighted Average Cost of Capital including long-term debt, preferred stock, and common stock
- In addition to the five cost of service elements a project specific depreciation expense is included in the annual revenue requirement
- Total Annual Revenue Requirement for a project is equal to the five cost of service elements plus the project specific depreciation expense and any applicable true-ups

Overview of Attachment GG Annual Revenue Requirement Calculation

- Applies to Multi-Value Projects cost shared project types
- Annual Allocation factors are calculated for each of the following cost of service elements based on the current cost structure for the entire Transmission Owner system:
- Transmission Operation and Maintenance (As a project's accumulated depreciation increases a greater share of the total transmission O&M expense for a TO's system will be recovered through that project)
- Other Operation and Maintenance Expense (based on Gross Transmission Plant) includes Administrative & General Expenses
- General and Common Depreciation Expense (based on Gross Transmission Plant) examples include office buildings, computers, etc…
- Taxes Other than Income Taxes (based on Gross Transmission Plant) examples include payroll and property taxes
- Income Taxes (based on Net Transmission Plant) Federal and State Income Taxes
- Return on Rate Base (based on Net Transmission Plant) Rate of Return based on the Weighted Average Cost of Capital including long-term debt, preferred and common stock
- In addition to the six cost of service elements a project specific depreciation expense is included in the annual revenue requirement
- Total Annual Revenue Requirement for a project is equal to the six cost of service elements plus the project specific depreciation expense and as applicable true-ups

Schedule 26

- Schedule 26 – Network Upgrade Charge for BRP (prior to 2013), GIP, and MEP
- Demand based charge for Transmission Service in addition to Schedules 7, 8, or 9 depending on the type and duration of Transmission Service taken
- For Point-to-Point Transmission Service that sinks in PJM Schedule 26 is discounted to zero
- Load served under Grandfathered Agreements are not charged Schedule 26 charges
- Rates updated January 1 and June 1 of each year
- Invoiced Monthly

https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

Schedule 26-A

- MVPs are charged to Monthly Net Actual Energy Withdrawals (MNAEW), Export Schedules, and Through Schedules proportional to the amount of energy withdrawn from the system

– Export and Through Schedules sinking in PJM are excluded from MVP charges

– Load served under Grandfathered Agreements are not charged Schedule 26-A

- Formulas used to calculate MVP Usage Rate ($/MWh)

– MVP Usage Rate = (Total MVP Annual Revenue Requirements * Monthly Withdrawal Weighting Factor) / (Monthly Net Actual Energy Withdrawals + monthly Real-Time Export Schedules + monthly Real-Time Through Schedules +MWhs of service provided under GFAs)

– Monthly Withdrawal Weighting Factor = Applicable Month Prior Year Withdrawals/ Total Prior Year Withdrawals

– Invoiced Monthly

Proposed Cross-Border Cost Sharing Methodologies

- Cost allocation based on Load Ratio Share
- Cost allocation based on directional flows—100% to importing region, and then load ratio share within region
- Market Efficiency Projects based on some percentage (70/30 import/export beneficiaries)

-Cost allocation based on directional flows, 70% to importing region, and 30% to exporting region

-Further allocation within local resource zones

-Load Ratio Share within local resource zone

-Additional accounting for ratio share of total flows

Another Cost allocation method by: MWh Energy

- Simple to understand and easy to administrate
- Reflects load growth and other system changes
- Rates remain generally stable as long as consumption does not change dramatically.
- Reinforces incentives for energy efficiency
- Implicit recognition of public good (like reliability of the system)

Cost allocation by: Peak MW

- Simple to understand and easy to administrate
- Reflects load growth and other system changes
- Rates remain generally stable
- Reinforces incentives for energy efficiency and demand response
- Implicit recognition of public good (like reliability of the system.)