Market Efficiency Study Process and RTEP Window Project Evaluation Training

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Agenda

1. Training Objectives
2. Market Efficiency Overview
3. Market Efficiency Base Case Input Assumptions
4. Market Efficiency Analytical Software
5. PJM Market Efficiency Benefits Calculation
6. Long-Term Window Process
7. Market Efficiency Analysis of Proposed Solutions
8. Acceleration and Re-evaluation Processes
9. 2022/23 Long-Term Window Registration Process

To Provide an Overview of:

- The models and tools used for Market Efficiency simulations including input assumptions
- The analysis and criteria required to assess the economic value of Market Efficiency Projects
- The Market Efficiency proposal window process

PJM Market Efficiency Overview

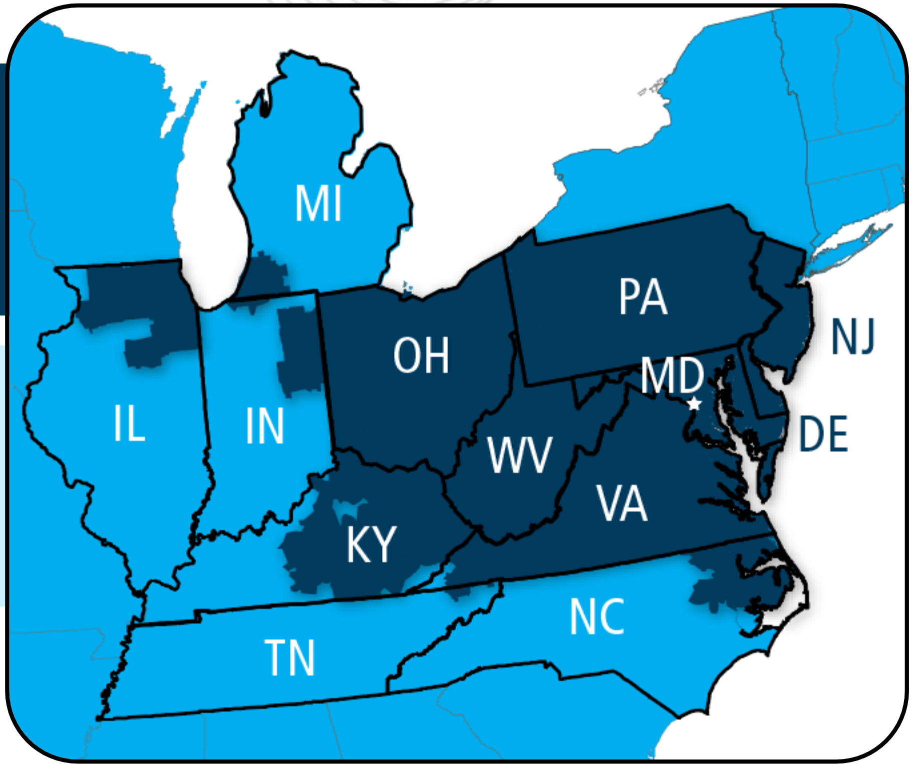
PJM Market Simulations Context

PJM Interconnection coordinates the planning of the bulk electric system through all or parts of 13 states and D.C.

PJM participates in interregional planning activities with all of its interconnected *Planning Coordinator neighbors.*

The PJM Market Efficiency process simulates the electric market using production costing software to:

- Understand internal and interregional congestion
- Assess future energy and capacity market congestion
- Approve economic-based transmission upgrades



Mitigating Congestion Costs

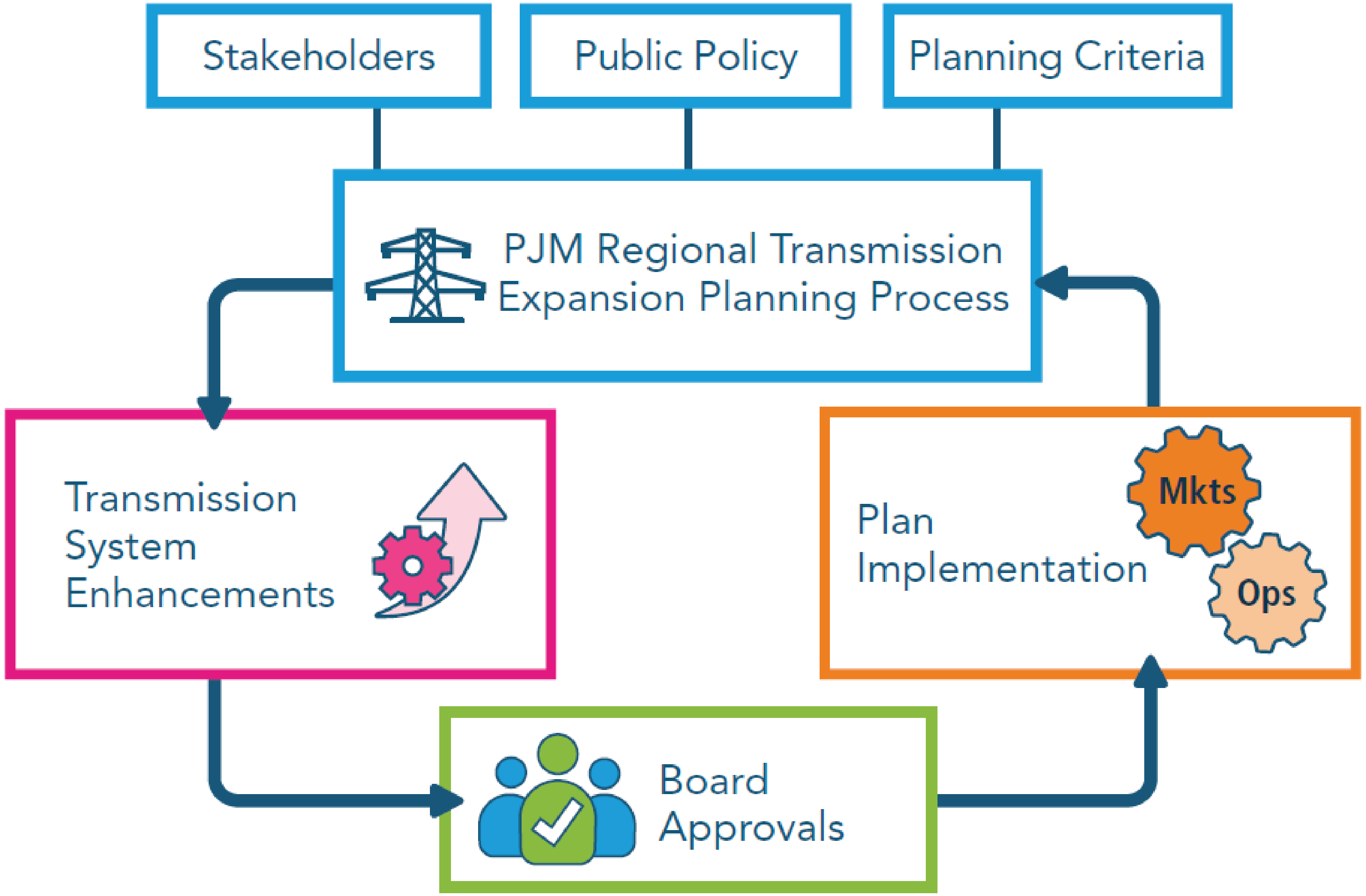
Congestion is a measure of the extent to which marginal generating units are dispatched to serve load due to transmission constraints.

Congestion occurs when available, least-cost energy cannot be delivered due to transmission constraints. As a result, higher-cost units must be dispatched to meet load.

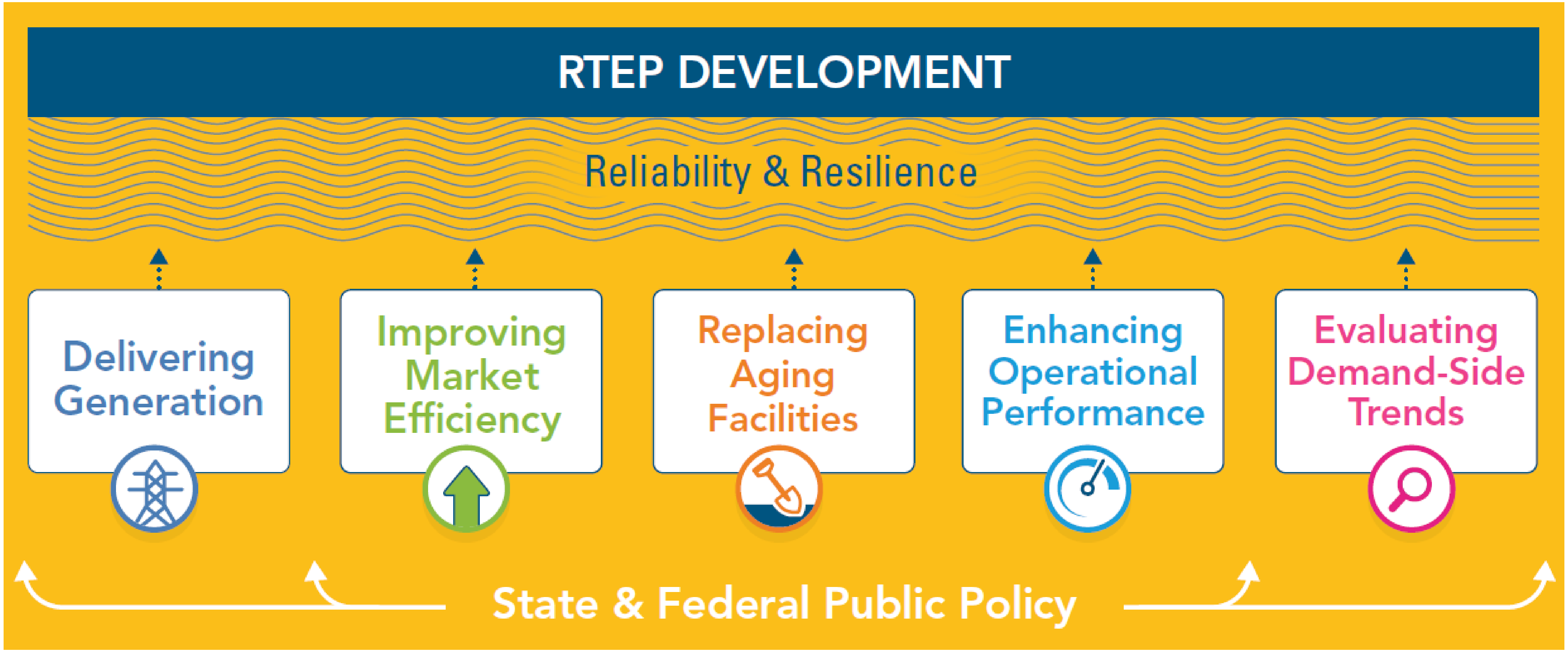
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,300	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,770	4.1%
2011	$999	(29.8%)	$35,890	2.8%
2012	$529	(47.0%)	$29,180	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%
2019	$583	(55.5%)	$41,680	1.4%
2020	$529	(9.4%)	$36,280	1.5%
2021	$995	88.2%	$54,130	1.8%

Data Source: Monitoring Analytics, LLC, 2021 State of the Market Report for PJM, Table 11-11 Total PJM congestion costs (Dollars (Millions)): 2008 through 2021

Regional Transmission Planning Process (RTEP)



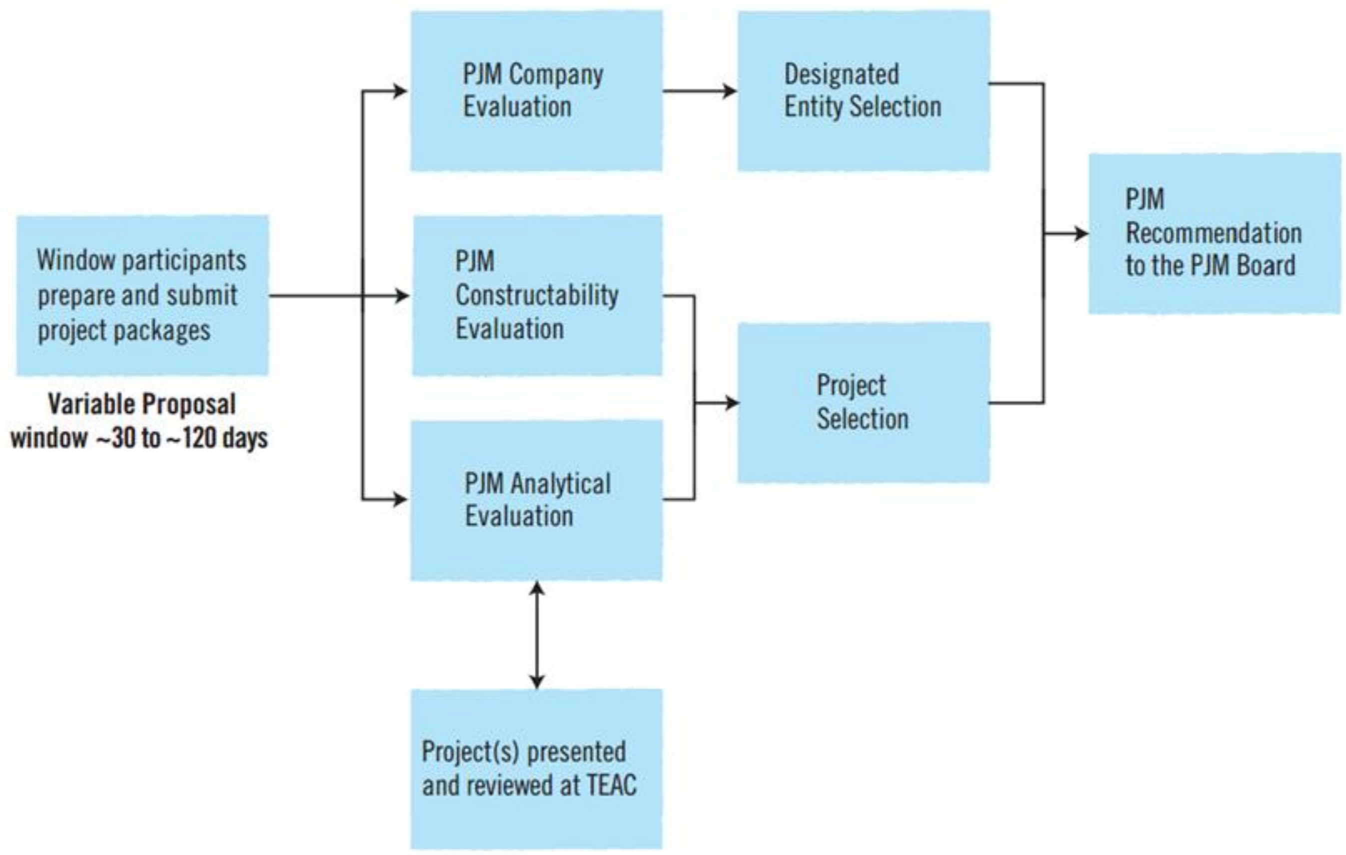
Data Source: PJM, 2021 Regional Transmission Expansion Plan (RTEP), Figure 1.1: RTEP Process – RTO Perspective



Data Source: PJM, 2021 Regional Transmission Expansion Plan (RTEP), Figure 1.2: System Enhancement Drivers

FERC Order 1000 – Competitive Planning Process

- **July 21, 2011:** FERC issues Order 1000 (RM10-23-000)
- Opportunity for non-incumbent transmission developers to submit project proposals through an RTEP process window to be considered for project construction, ownership, operation and financial responsibility
- One or more needs: reliability, market efficiency, operational performance, public policy



Objective of PJM Market Efficiency

Operating Agreement : 1.5.7 Development of Economic-Based Enhancements or Expansions

(b) Following PJM Board consideration of the assumptions, the Office of the Interconnection shall perform a market efficiency analysis to compare the costs and benefits of: (i) accelerating reliability-based enhancements or expansions already included in the Regional Transmission Plan that if accelerated also could relieve one or more economic constraints; (ii) modifying reliability–based enhancements or expansions already included in the Regional Transmission Plan that as modified would relieve one or more economic constraints; and (iii) adding new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified. Economic constraints include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) pro-ration of Stage 1B ARR requests as described in the Operating Agreement, Schedule 1, section 7.4.2(c); or (3) significant simulated congestion as forecasted in the market efficiency analysis. The timeline for the market efficiency analysis and comparison of the costs and benefits for items in the Operating Agreement, Schedule 6, section 1.5.7(b)(i-iii) is described in the PJM Manuals..

(c) The process for conducting the market efficiency analysis described in subsection (b) above shall include the following:

(i)The Office of the Interconnection shall identify and provide to the Transmission Expansion Advisory Committee a list of economic constraints to be evaluated in the market efficiency analysis.

Economic Justification for Market Efficiency

Operating Agreement : 1.5.6 Development of the Recommended Regional Transmission Expansion Plan

(i) The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in accordance with the procedures, criteria and analyses described in the Operating Agreement, Schedule 6, sections 1.5.7 and 1.5.8.

PJM Governing Documents – Market Efficiency Guidelines

Objective of PJM Market Efficiency

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(i) ... ent of the Of... dance with the ...

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Market Efficiency Analysis Objectives

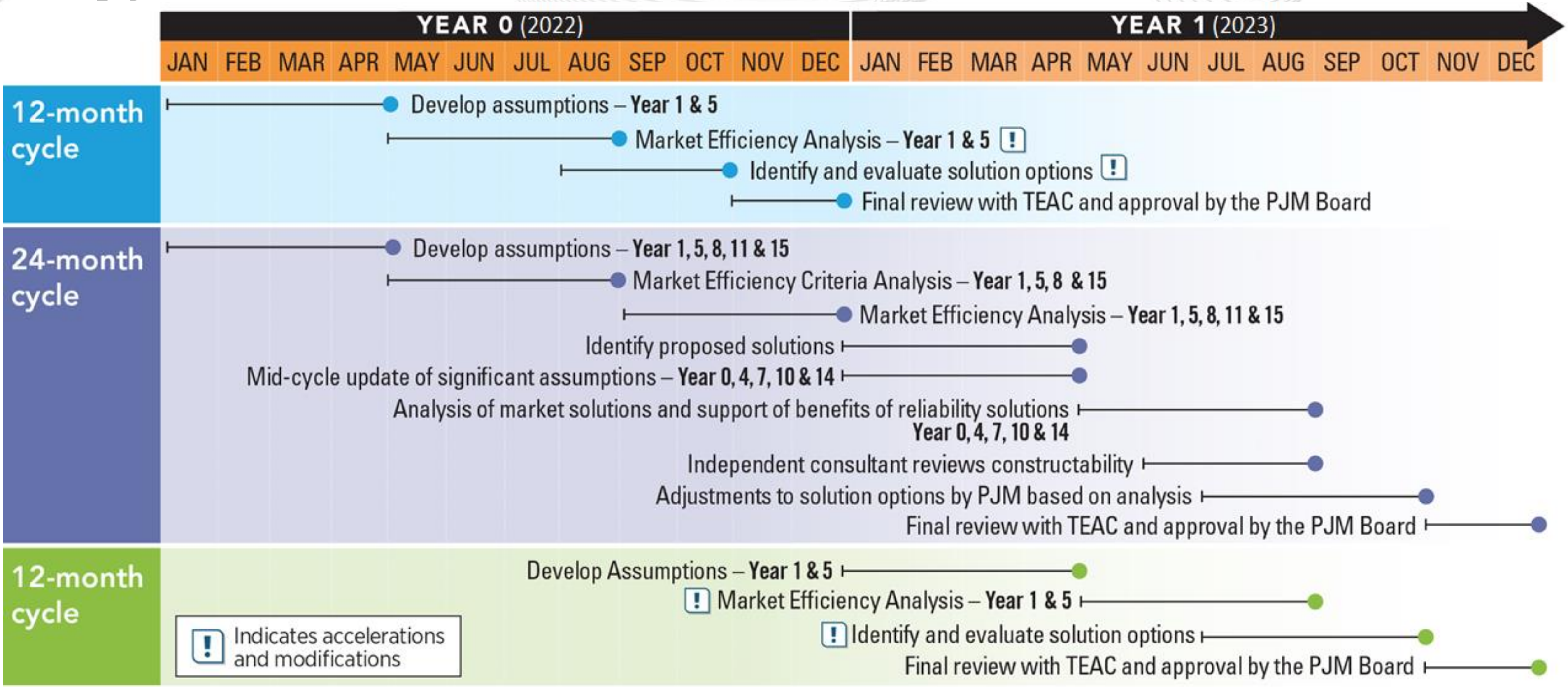
- **Long-Term Window**
  Identify new transmission projects that may result in economic benefits

- **Re-evaluation Analysis**
  Review cost and benefits of economic-based transmission projects included in the RTEP to assure that they continue to be cost beneficial

- **Acceleration Analysis**
  Determine which reliability-based transmission projects, if any, have an economic benefit if accelerated or modified

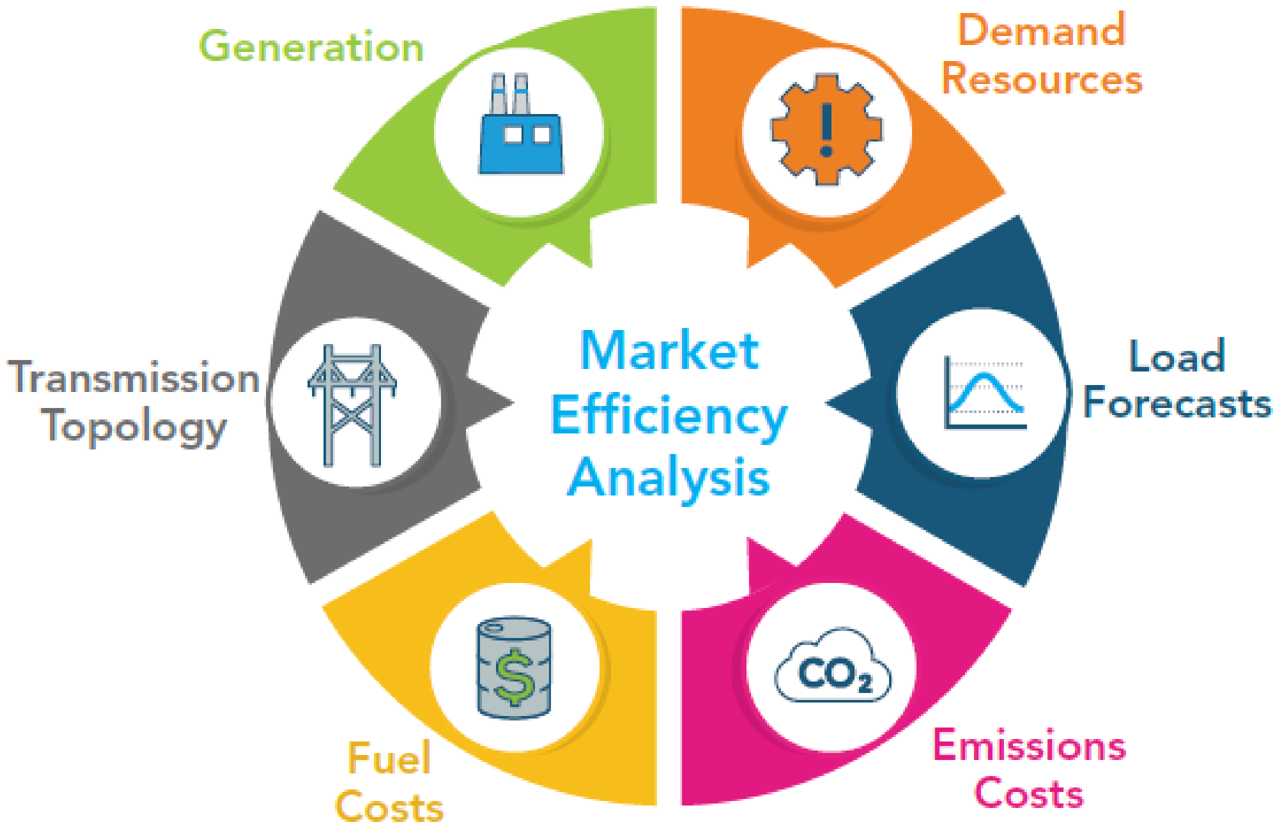
- **“Hybrid” Projects**
  Design in more robust manner reliability-based transmission projects already included in the RTEP that when modified would provide economic benefits by relieving one or more economic constraints

Market Efficiency Cycle



Market Efficiency Input Assumptions

Market Efficiency Inputs Overview



PROMOD Base Case Input Data

PROMOD SCED Simulation

Generation Expansion Plan (ISA/FSA)

Demand Response Forecast

Intermittent resource hourly shapes

Transmission Topology (As-Is, RTEP)

Fuel Price Forecast: Natural Gas, Coal, Oil-H, Oil-L

Topology Mapping: Bus-Area, Bus Load-Demand, Gen-Bus (As-Is, RTEP)

Emissions Price Forecast: SO_2, NOx (seasonal, annual), CO_2 (National, RGGI)

Reactive Interface PV Analysis

Demand Forecast: Annual Peak Load and Energy, Hourly shapes

Monitored lines and contingencies, interfaces and nomograms, PARS

Interregional Inputs

MISO and NY Updates: GenExp, load forecast, wind profiles, major upgrades, flowgates, transactions with SPP/MRO, imports Canada

Pool Interaction Modeling: M2M flowgates, pseudo-ties, DC schedules, hurdle rates, import/export limits

PROMOD Inputs – Generation Expansion Plan

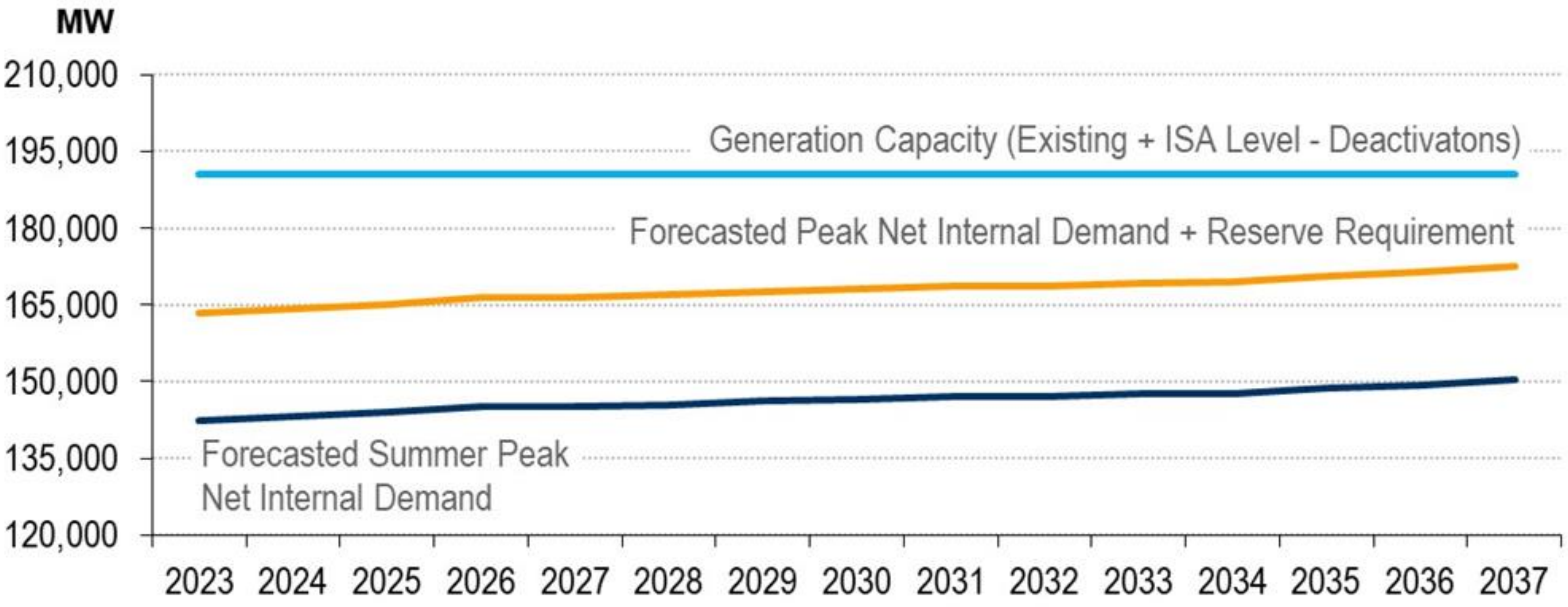
- Generation Expansion model refers to the creation and verification of an expected resource plan for the PJM active footprint within the production cost simulations.

- Expected base generation resources include:
  - In-service generation
  - Active queue generation with executed Interconnection Service Agreement (ISA) or executed Interim ISA
  - Retirement of expected future deactivations – announced deactivations

- PJM's Generation Expansion Plan is synchronized with the machine list usually posted by Transmission Planning at February TEAC.

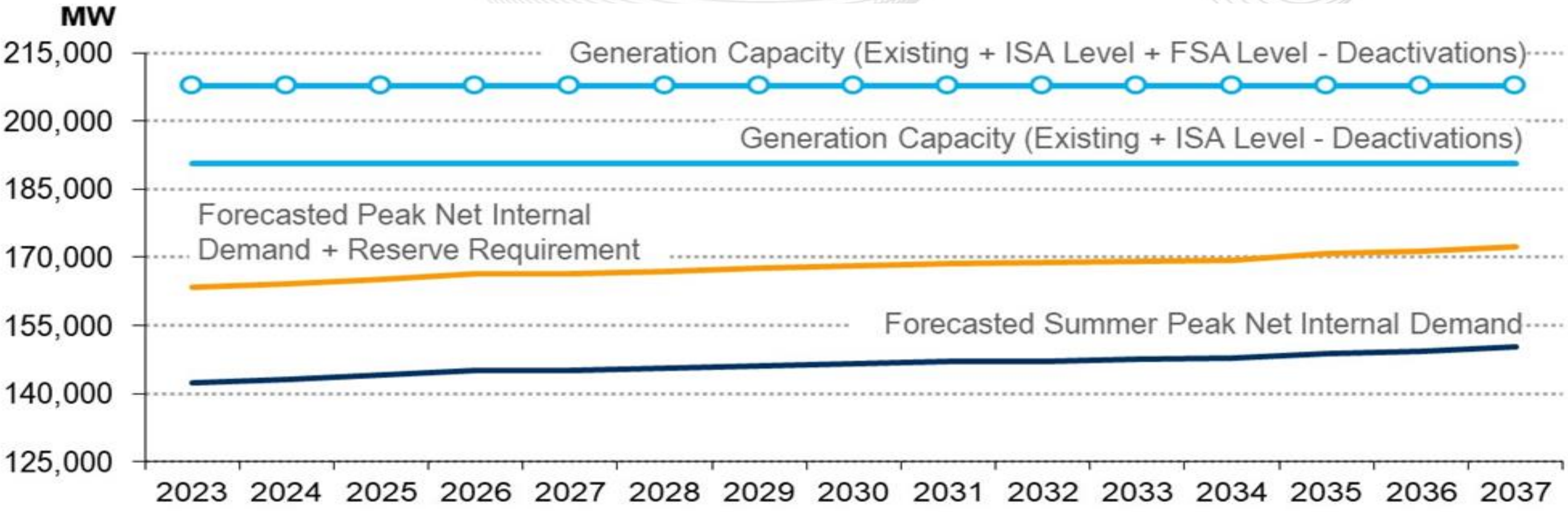
2022 Market Efficiency Window Reserve Margin

PJM Market Efficiency Reserve Margin – With Uniform Expansion



Notes: *Generation includes existing and projected PJM internal capacity resources. Solar and wind resource capacity at 38% and 13% of maximum capability, respectively. Model informed by the 2027 RTEP Powerflow and the Generation Interconnection Queue.*

FSA Sensitivity



Notes: Generation includes existing and projected PJM internal capacity resources. Solar and wind resource capacity at 38% and 13% of maximum capability, respectively. Model informed by 2027 RTEP Powerflow and the Generation Interconnection Queue

Additional modeled PJM generating capacity can be considered to test the robustness of solution proposals.

This sensitivity also includes active queue generation identified as an FSA unit (Facility Study Agreement) or having a suspended ISA (Interconnection Service Agreement) mapped to the five-year-out RTEP load flow case.

Generation Expansion Plan – Modeled Inputs

Operational Parameters

- Unit Heat Rates
- Summer & Winter Capability
- Bus Mapping
- Hourly Profiles for Intermittent Resources
- Outage Rates
- Minimum Downtime
- Minimum Runtime
- Spinning Reserve Contribution
- Must Run Status

Cost Parameters

- Fuel Cost
- Emissions Cost
- Variable O&M
- Curtailment Prices for Solar and Wind
- Startup Cost

PROMOD Inputs – Fuel Forecast

Forecast Prices Developed by the Hitachi Energy Fuels Group Using a Reference Case Model

15-Year Gas and Oil Price Forecasts

- Prices derived from NYMEX (short term) and the EIA Annual Energy Forecast (long term)
- Monthly gas burner-tip prices at a zonal level – include commodity and basis price forecast
- Monthly oil burner-tip prices at a system level

15-Year Coal Forecast Model

- Mining costs, emission price forecasts, transportation routes and pricing, coal quality
- Annual coal prices at a unit level

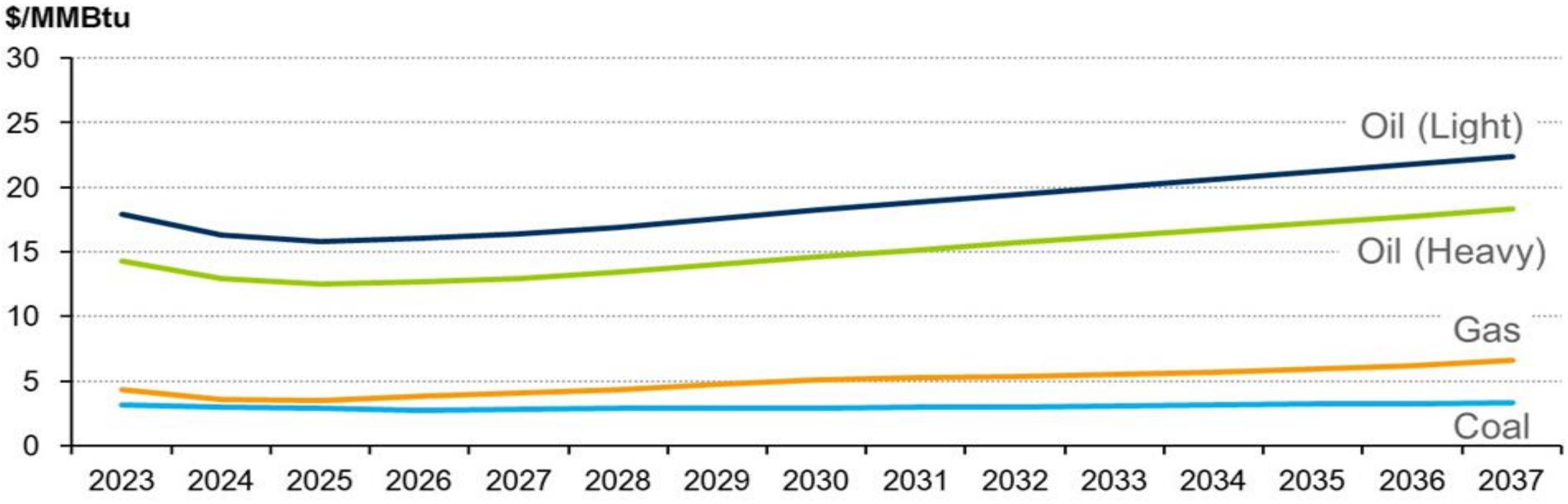
2022 Fuel Forecast

The natural gas prices depicted are representative of the commodity cost (Henry Hub).

PROMOD uses basis adders to capture the gas transportation costs of the commodity to the different PJM zones.

- The oil prices are representative of burner-tip prices and are the same throughout PJM.
- The coal prices are the average of each PJM coal plant's burner-tip price.

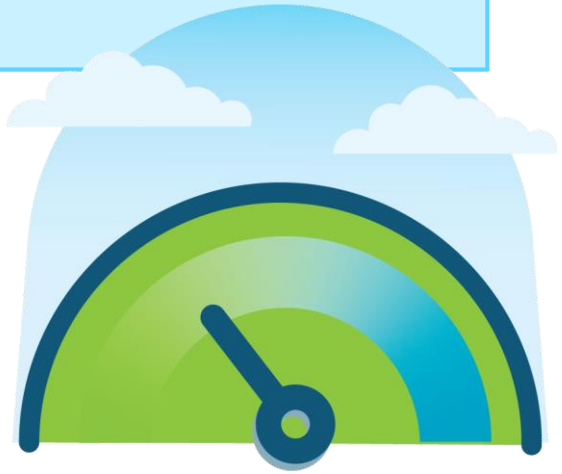
The PROMOD coal price forecast is on an individual plant-specific delivered basis.



Emissions Prices and Release Rates Developed by Hitachi Energy

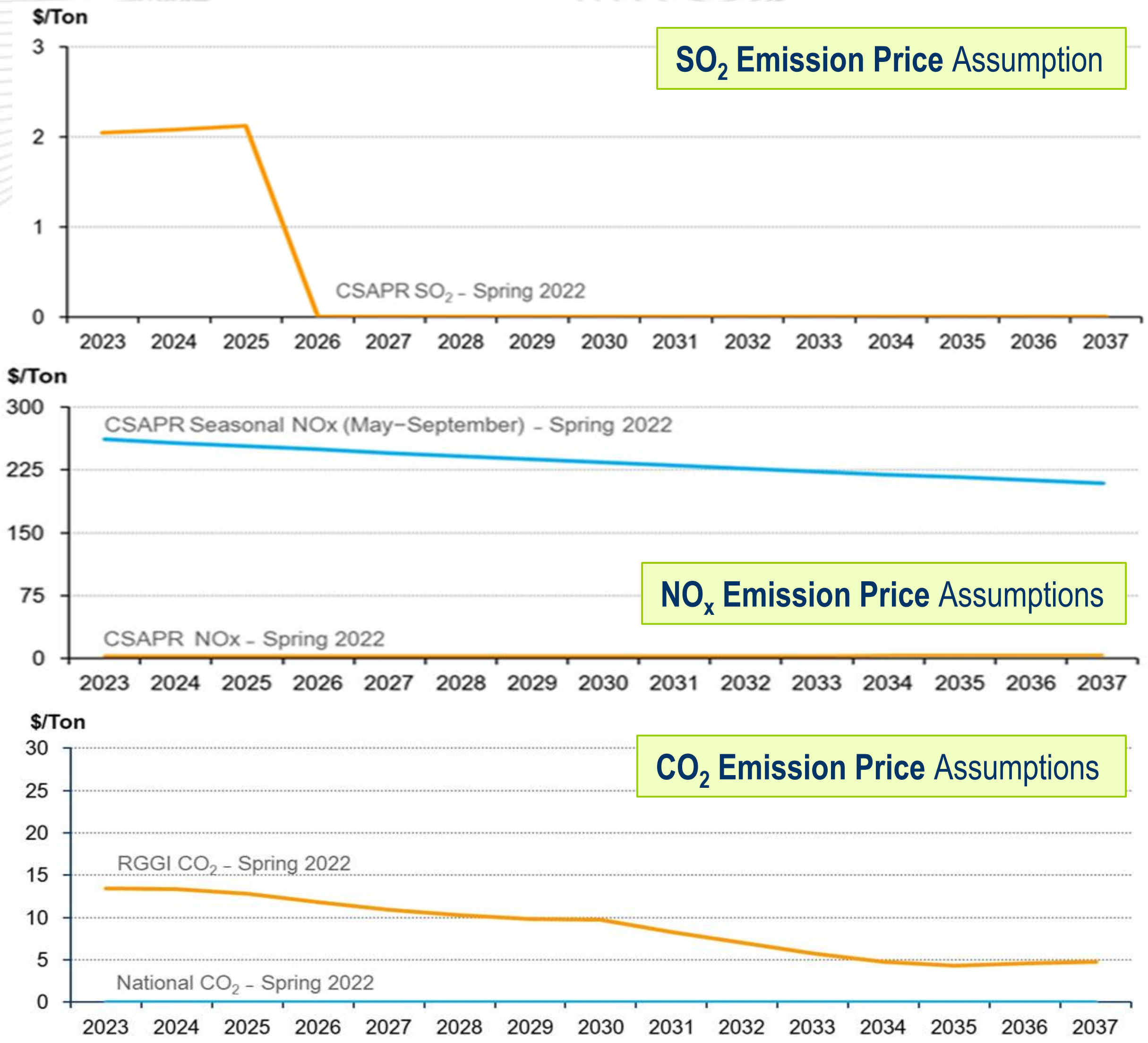
- Three major effluents modeled: SO_2, NO_x, and CO_2
- Effluents assigned to generators based on location and effective trading program
- Unit or fuel use release rates
- Sources: EPA CEMS data and vendor's proprietary Emission Forecast Model (EFM)

- PJM will monitor consistency with expected emissions legislation affecting PJM Generators.



2022 Emissions Forecast

- CO_2 emission forecast is based on analysis associated with national and regional legislative proposals.
- Forecasts for SO_2 and NO_x reflect legislation associated with the Cross State Air Pollution Rule (CSAPR).
- Charts show graphs of emission prices assumed in the Market Efficiency base case.



PROMOD Inputs – Load Forecast

PJM Load Forecast Report

- Peak load and annual energy
- Load forecast mapped to PROMOD areas

Hitachi Energy Synthetic Demand Shapes

- Based on the average of several years of load shapes
- Hourly load shapes merged to match PJM load zones

Demand Response

- Modeled as discrete units
- Amount based on the levels outlined in the PJM Load Forecast Report

Peak load and annual energy forecasts for the PJM RTO were developed by PJM's Resource Adequacy Planning Department.

Released in the January 2022 PJM Load Forecast Report

Table Shows:

- Annual PJM peak and annual PJM energy forecast
- Provides the basis for load input into the Market Efficiency simulations

2022 PJM Peak Load and Energy Forecast

Load	2023	2027	2030	2033	2037
Peak (MW)	149,351	152,322	153,755	154,767	157,689
Energy (GWh)	787,761	815,527	830,618	848,695	877,586

PROMOD Inputs – Demand Response

Demand Response (DR) is based on the amount outlined in the PJM Load Forecast Report by delivery year, zone and product type.

Demand Response is modeled as discrete units.

- Location of DR informed by zip code of registration data
- Strike price modeled to ensure that DR is called at a level consistent with history and contractual requirements for the product type

2022 PJM Demand Resource Forecast					
	2023	2027	2030	2033	2037
Demand Resource (MW)	7,065	7,167	7,219	7,253	7,348

PROMOD Inputs – Intermittent Resource Profiles

Hitachi Energy provides hourly wind and solar profiles.

- Based on National Renewable Energy Laboratory (NREL) data

New units are mapped to existing profiles based on technology and location.

Curtailment is allowed if Local Marginal Price (LMP) dips under minimum threshold.

PROMOD Inputs – Transmission Topology

New project evaluation is performed using a current year + 5 RTEP Transmission Model.

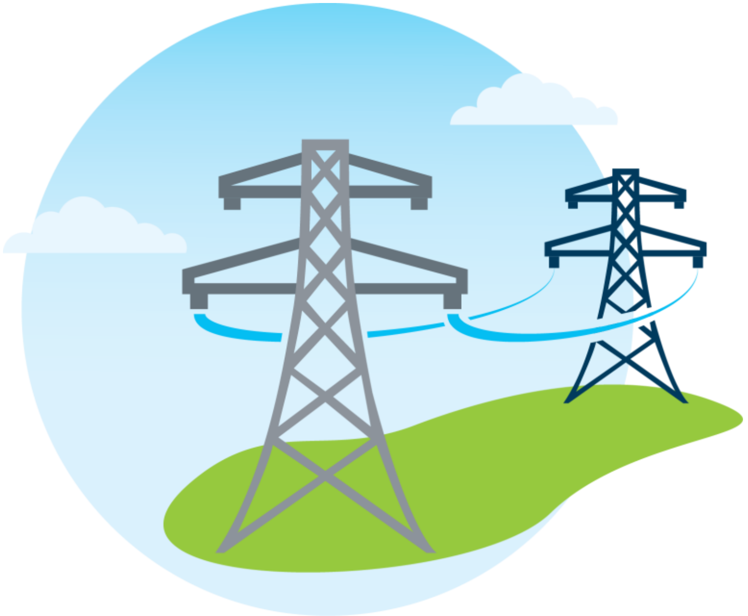
All approved baseline upgrades

Same topology used for all study years.

To evaluate a project expected to be in service in 2027, the same topology is used in the pre-2027 study years simulated in PROMOD IV.

External world topology

Derived from Multi-Regional Modeling Working Group (MMWG) Series



PROMOD Inputs – Flowgates

Thermal Flowgates

- Historical market constraints
- N-1 Flowgate Screening performed on Summer Peak, Winter Peak, and Light Load +5 RTEP Transmission Models

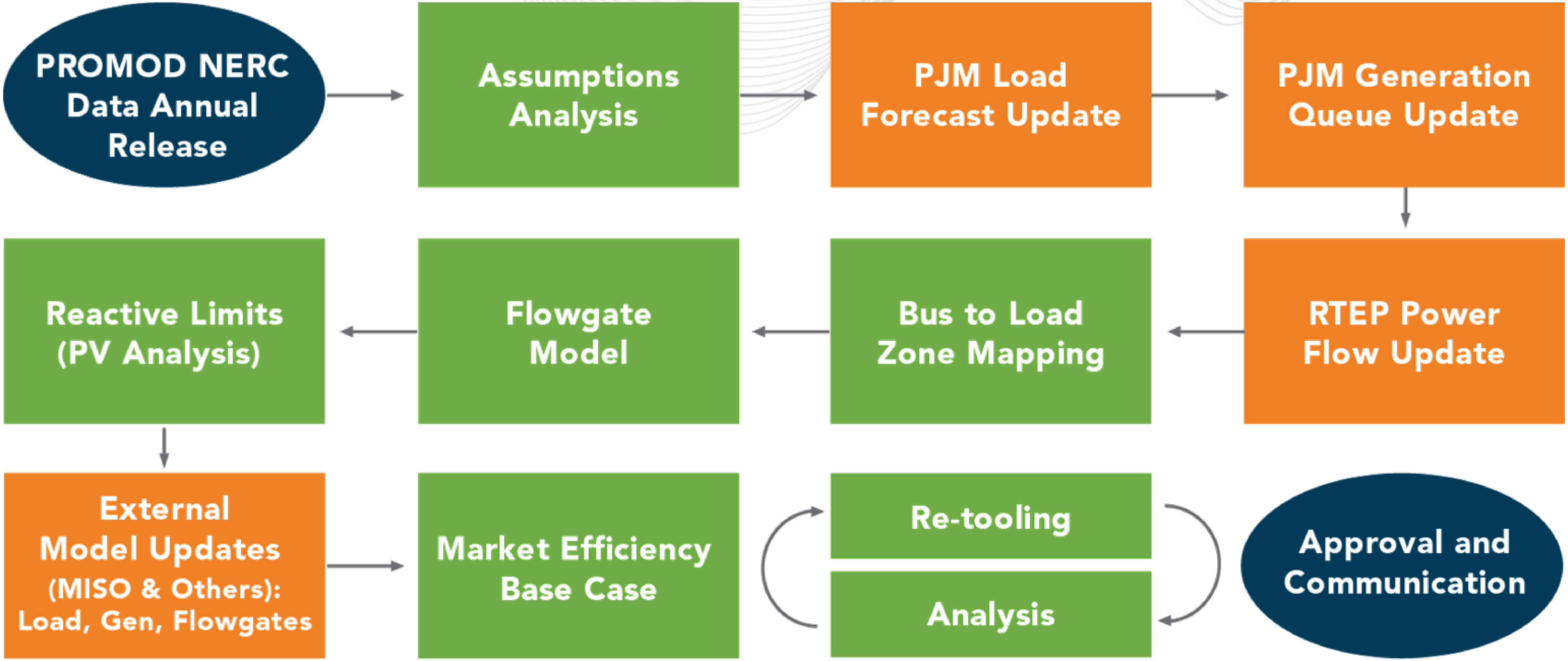
Transmission Ratings Modeling

- Summer from +5 RTEP Summer Peak Transmission Model
- Winter from +5 RTEP Winter Peak Transmission Model

Reactive Limits

- PV Analysis to develop summer, winter and light-load megawatt transfer limits for significant interfaces in PJM
- Modeled interfaces: AEP-DOM, AP South, Black Oak-Bedington, 5004/5005, Central Interface, Eastern Interface, Western Interface, Cleveland Interface, BC PEPCO Interface

Market Efficiency Work Flow



Market Efficiency Analytical Software

PJM uses PSS/E, TARA and similar tools for load flow analyses:

N-1 Contingency Analysis

- Determine flow impact of transmission system changes/upgrades
- For hours during the year when the system would be the most stressed (Summer/Winter Peak, Light Load with high wind)

Flowgate Identification

- Determine the flowgates to monitor in production model

PV Analysis

- Transfer analysis to determine the impact of transmission system changes/upgrades on reactive limits

PJM uses PROMOD for economic analysis:
Determine zonal load payments and congestion benefits

Simulate electric market operations over a study period

- Models incorporate future demand, generating unit operating characteristics, fuel forecast, and transmission topology and constraints.
- Calculate hourly production costs, location-specific market clearing prices, line and interface congestion values, and zonal load payments.

Engine using an hourly chronological security constrained unit commitment and economic dispatch simulation

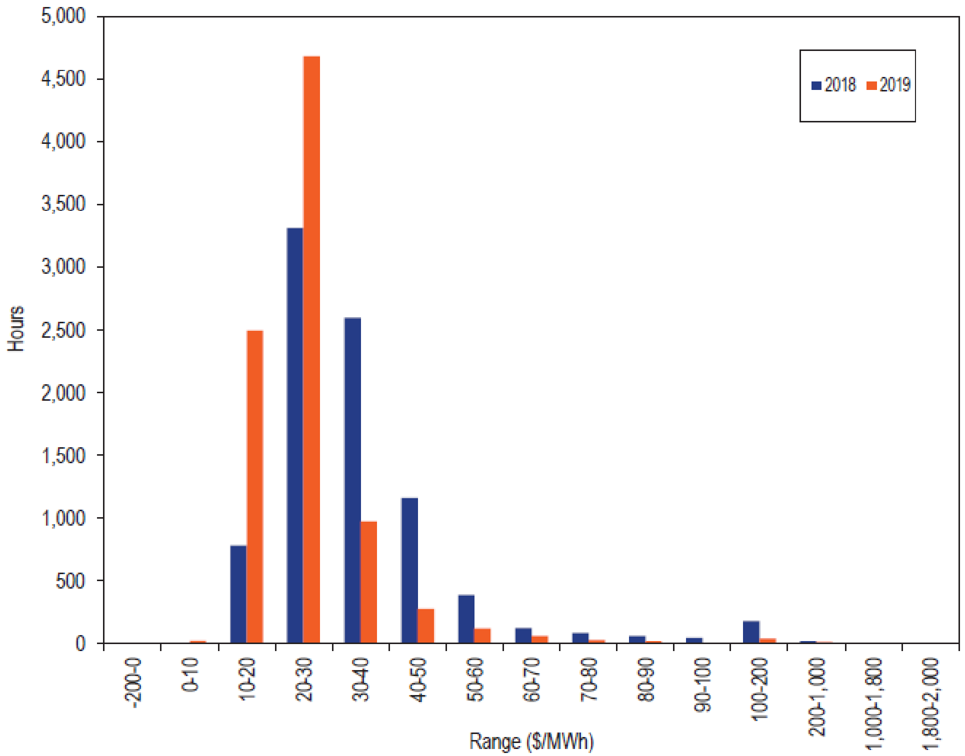
Minimize production costs while simultaneously adhering to a wide variety of transmission and operating constraints.

Network model uses DC power flow

A linearization of the AC power flow that models line thermal limits but is less detailed than load flow models

Advantages of Production Costing Models

- Simulate all the hours in a year, not just peak hour as in power flow models
- Allows planners and utilities to understand the energy price impacts:
  - LMP and its components
  - Load Payments
  - Production Cost



Data Source: Monitoring Analytics, LLC, 2019 State of the Market Report for PJM, Figure 3-23 Average LMP for the Real-Time Energy Market: 2018 and 2019

Enables the simulation of the market on a forecast basis ✚ **Allows analysts to evaluate the economic impacts of energy market decisions**

Production Costing Model vs. Load Flow Model

Production Cost Model	Power Flow Model
▪ Security Constrained Economic Dispatch (SCED)	▪ Merit Order Dispatch
▪ All hours (8,760 hrs./year)	▪ Peak hour
▪ DC transmission	▪ AC and DC
▪ Selected security constraints	▪ Large numbers of security constraints
▪ Market analysis/transmission analysis/planning	▪ Basis for transmission reliability & operational planning

PROMOD

- Fundamental electric market simulation tool by Hitachi Energy
- Recognized in the industry for its flexibility and breadth of technical capability, incorporating extensive modeling details
- Incorporates extensive details, including generating unit operating characteristics, transmission grid topology and constraints
- Used for Locational Marginal Price (LMP) forecasting and transmission analysis

PROMOD Inputs/Outputs

Inputs

- Generation data
- Demand & energy
- Fuel forecasts
- Environmental costs
- Power flow case
- Monitored flowgates
- Other information: reserve requirement, market territory, etc.

PROMOD

Production Costing Software

Outputs

- Hourly LMP of buses and hubs, include energy, loss and congestion components
- Hourly unit generation and production cost
- Hourly binding constraints and shadow prices
- Hourly line flows
- Hourly company purchase/sale
- Environmental emissions
- Fuel consumption

PROMOD Computational Challenges

Challenge – High Number of Large Production Costing Runs

Large Simulation Footprint: Co-optimizing dispatch across multiple RTOs

Generators	5,700+
Buses	89,000+
Branches	110,000+
Monitored Lines	4,400+
Contingencies	1,500+

Run Time: 34–40 hours

One simulated year: 8,760 hours

Illustrative Example

Total PROMOD Simulations

32
Transmission Proposals

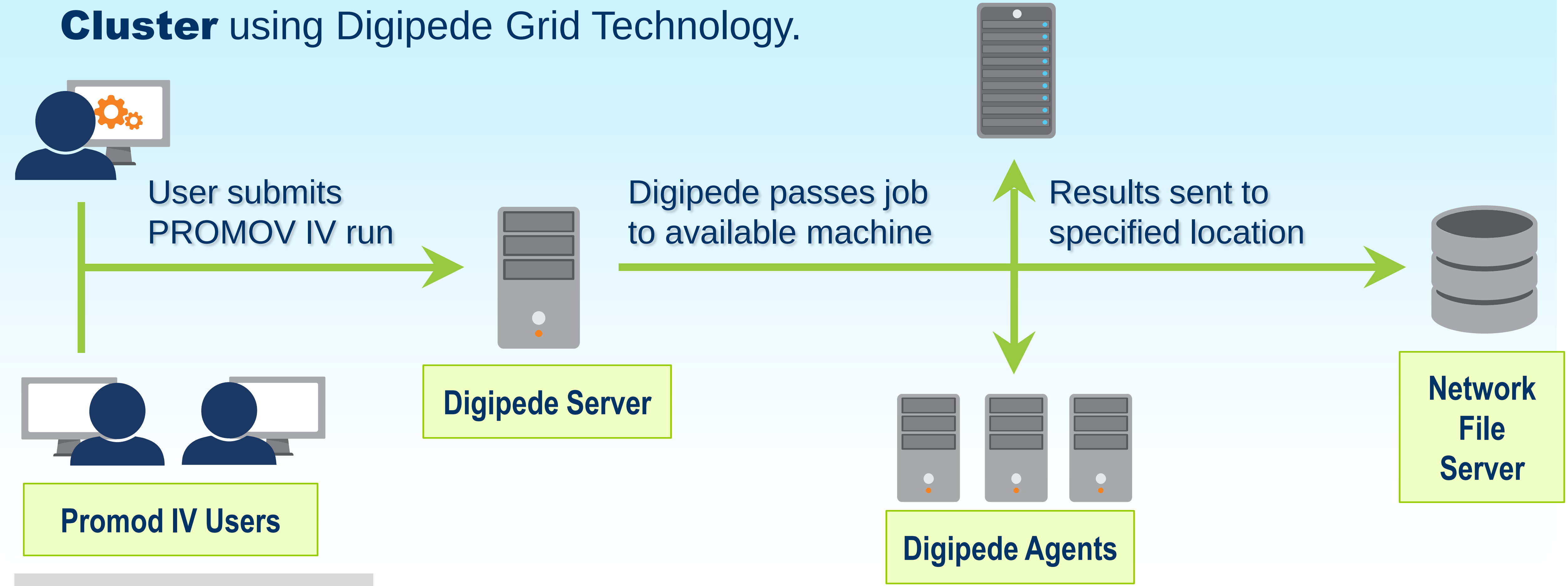
5
Sensitivity Scenarios

4
Simulated Years
(2019, 2023, 2026, 2029)

Total PROMOD Simulations: 32*5*4 = 640
Total Runtime: ~ 21,760 – 25,600 hours

Post processing such a large amount of PROMOD output data requires significant resources.

PJM PROMOD High-Performance Computer Cluster using Digipede Grid Technology.



Source: http://www.digipede.net/

PJM Market Efficiency Benefits Calculation

Market Efficiency Projects may address:

- Energy market constraints (drivers)
- Capacity market constraints (drivers)

Market Efficiency Projects may generate:

- Energy market benefits
- Capacity market benefits (RPM benefits)

Total Benefits = **Energy Benefits + RPM Benefits**

PJM Market Efficiency Benefits Calculation – Energy

Energy Benefits Calculation

Regional Projects 345 kV double circuit or above	50% Change in Total Energy Production Cost **+** 50% Change in Load Energy Payment*
Lower Voltage Projects 345 kV single circuit or below	100% Change in Load Energy Payment*

**Note: Only for zones with decrease in net load payments*

Energy Benefits Calculation (Con't.)

Change in Total Energy Production Cost	▪ Calculated for the PJM region ▪ Adjusted for interchange with neighboring pools

Change in Load Energy Payments	▪ Calculated for each transmission zone ▪ Only zones that show a LMP decrease will be considered

Net Load Payment (NLP) Benefit for a Zone

The change in the Net Load Payment with the addition of the project versus without the project determines the project benefits to the demand zones.

NLP is calculated as the annual sum of the hourly estimated zonal load megawatts for each PJM transmission zone multiplied by the hourly estimated zonal Locational Marginal Price for each PJM transmission zone minus the value of Transmission Rights for each PJM transmission zone.

$$\boldsymbol{NLP} = \sum_{\text{Buses/Hours}} (Hourly\ Bus\ Load \times Hourly\ Bus\ LMP) -$$

$$8{,}760 \times ARR\ Path\ Cleared\ MW \times (Annual\ Sink\ Node\ CLMP - Annual\ Source\ Node\ CLMP)$$

PJM Wide Adjusted Production Cost Benefits

The change in the Adjusted Production Cost (APC) with the addition of the project versus without the project determines the APC project benefits to the PJM pool.

APC is calculated as total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region, adjusted for the interchange with the neighboring pools.

- Purchases valued at the Load Weighted LMP
- Sales valued at the Generation Weighted LMP

$$\boldsymbol{APC} = \sum_{Units}^{Base\ Case} \left[(Fuel\ Costs + Emission\ Costs + Variable\ O\&M) \right.$$

Energy Benefits Details

Item	Production Cost Benefits	Load Payment Benefits
Granularity	PJM region	Benefitting Transmission Zones
Simulated Years	Four years (RTEP-4, RTEP, RTEP+3, RTEP+6)	
Trend	Interpolated between the simulated years and extrapolated after the last simulated years	
Benefits Horizon	Calculated for 15 years starting with the RTEP Year (Net Present Value)	

PJM Market Efficiency Benefits Calculation – Capacity

Capacity Benefits Calculation

- Planning Parameters
- Capacity market supply sell offers
- Load forecast

→ **Base Residual Auction Engine** →

- Load Capacity Payments
- System Capacity Cost

Capacity Benefits Calculation (Cont.)

Regional Projects 345 kV double circuit or above	50% Change in System Capacity Cost + 50% Change in Load Capacity Payment*
Lower Voltage Projects 345 kV single circuit or above	100% change in Load Capacity Payment*

**Note: Only for zones with decrease in capacity payments*

Capacity Benefits Calculation (cont.)

Change in Total System Capacity Cost	Calculated for the PJM Region
Change in Load Capacity Payment	▪ Calculated for each transmission zone ▪ Only zones that show a decrease in capacity payment will be considered

Capacity Benefits Details

Item	Capacity Cost Benefits	Load Capacity Payment Benefits
Granularity	PJM Region	Benefitting Transmission Zones
Simulated Years	Two Years (RPM , RTEP)	
Trend	Interpolated between the simulated years and extrapolated after the last simulated years	
Benefits Horizon	Calculated for 15 years starting with the RTEP Year (Net Present Value)	

Market Efficiency Long-Term Window Process

Long-Term Window Process Overview

Identify Target Congestion Drivers

Solicit Proposals for Congestion Drivers

Analyze / Compare Proposals

Present Selected Solution at TEAC

PJM Board Approval

Identify Target Congestion Drivers

In determining eligible congestion drivers, PJM considers

- All binding flowgates internal to the PJM footprint (including tie lines)
- Current active Market-to-Market flowgates (NERC book of flowgates)
- Potential future Market-to-Market flowgates between PJM and MISO

Eligible congestion drivers

- Selected to focus proposals on significant issues
- Identified coincident with the opening of market efficiency proposal window

Proposals must address at least one identified congestion driver

- If the proposal does not substantially address an identified congestion driver, or is otherwise substantially deficient or is seriously flawed, it will be rejected, and the proposer will be notified

Market Efficiency Criteria for Target Congestion Drivers

Annual simulated congestion frequency of
at least 25 hours in each of the RTEP and RTEP+3 study years

Congestion Threshold

Thermal Constraints	Regional Constraints	Interregional Constraints
Minimum of **$1 million** congestion in each RTEP and RTEP+3 study years	Minimum of **$10 million** congestion in each RTEP and RTEP+3 study years	Minimum of **$0.5 million** congestion in each RTEP and RTEP+3 study years (lower threshold as there may be interregional benefits in addition to the regional benefits)

PJM may not recommend proposals for certain facilities meeting the criteria due to following exceptions:

- Congestion is significantly influenced by an FSA generator or a set of FSAs.
- Majority of the congestion was already addressed in previous window(s).
- Simulated congestion for future study years displays a declining trend.

Note: PJM reserves right to add other exceptions as necessary.

Market Efficiency Criteria for Target Capacity Drivers

Follows OATT Att. DD, Section 15 language

"Following each Base Residual Auction, for LDAs that had a price split, PJM determines if any Planned Generation Capacity Resources, Planned Demand Resources, or Qualifying Transmission Upgrades cleared"

Criteria for Posting Target Capacity Drivers

- **Price Split:** If a Locational Price Adder results from the clearing of an LDA for two consecutive Base Residual Auctions, **and**
- **No New Resources:** No such planned resources or upgrades cleared

Proposed solutions should be in service prior to June 1 of the delivery year for which the Base Residual Auction is being conducted.

In the event a transmission expansion cannot be placed in service by this date, PJM will consider solutions that can be placed in service later but no later than the RTEP year.

Competitive Windows To Solicit Proposals for Target Drivers

Energy Drivers

Open Long-Term Competitive Window (odd years) ***120 days January–April***

The problem statement, target congestion drivers, and modeling data are posted when the window opens.

- Includes market efficiency base case files for all study years, PROMOD input files and benchmark test cases and results
- To access the information, stakeholders required to have CEII confirmation and PROMOD vendor (Hitachi Energy) confirmation

Capacity Drivers

Open annual window as needed ***30 days***

Proposals Analysis and Comparison

Each valid proposal is tested for Benefits/Cost >1.25

Total Benefits = **Energy Benefits** + **Capacity Benefits**

Candidates passing B/C tests:

- Reducing congestion on target congestion driver
- Other factors
  - Overall PJM Congestion
  - PJM Net Load Payments
  - PJM Production Costs
- Perform Sensitivities
  - Gas Sensitivity
  - Load Sensitivity
  - Other sensitivities, as needed

- **Reliability Analysis**

  Additional reliability upgrades

- **Independent Cost Analysis**

  Projects exceeding $50M independent cost analysis

- **Constructability Analysis**
  - Verification of proposed schedule duration
  - Other risks to both cost and schedule

- **Project Combinations**
  - Combination of components of multiple projects
  - Incremental or multiple projects

Approval & Communication

Selected projects require PJM board approval

Approved projects are communicated at TEAC meetings

Letter from PJM notifying construction responsibility

Interregional Market Efficiency Project (IMEP) Process

Periodically PJM and MISO also conduct an Interregional Market Efficiency Project (IMEP) study

- Issues identification and benefit determination
  - conducted in each regional process consistent with current effective PJM-MISO Joint Operating Agreement (JOA)
- Interregional proposals ***must***:
  - Address at least one identified issue in each region (could be same issue if identified by both RTOs)
  - Be submitted to both regional processes

Note: Results presented at PJM-MISO IPSAC (Inter-Regional Planning Stakeholder Advisory Committee) meetings
https://www.pjm.com/committees-and-groups/stakeholder-meetings/ipsac-midwest.aspx

Interregional Evaluation Criteria

Benefits

Each RTO determines the project benefits using their respective regional process, metrics and assumptions (Tariff)

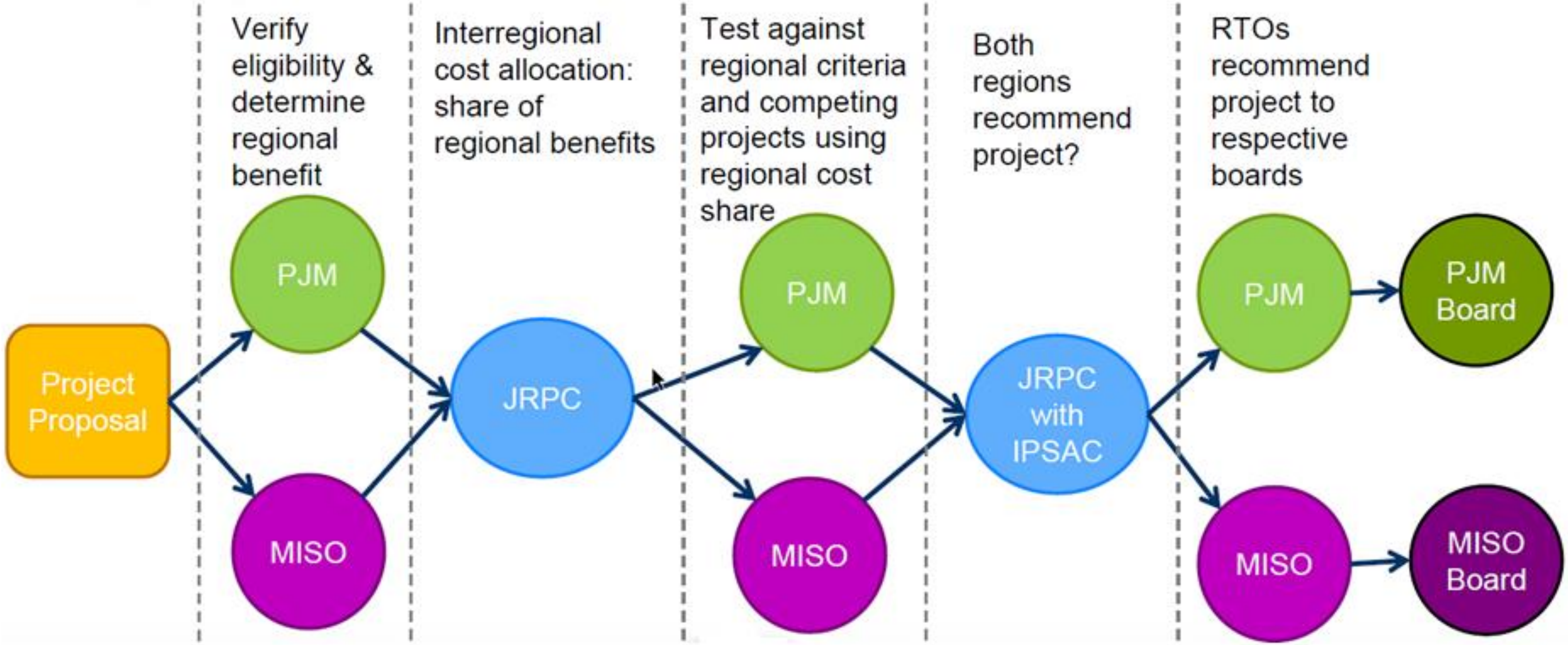
Costs

Costs are allocated interregionally based on pro rata share of benefits, as determined above

Interregional Projects Criteria

- Must meet the B/C criteria in each RTO (based on allocated costs)
- Qualify as an MEP under both the MISO and PJM process
- Be approved by each RTO’s Board of Managers

PJM/MISO IMEP Study Workflow



2022/2023 Long-Term Window
Market Efficiency Analysis of Proposed Solutions

2022/2023 Long-Term Window Schedule (Year 2022)

JAN. APR. MAY AUG. SEPT. OCT. NOV. DEC.

2022

Jan. – April
Develop PJM assumptions

May – Aug.
Build/update PROMOD model

Aug.
Post preliminary market efficiency base case

Sept.
Post whitepaper input assumptions

Sept. – Oct.
Interregional data update

Sept. – Nov.
Identify eligible congestion drivers

Nov.
Post sensitivity scenarios

Dec.
Post window materials:
- Problem statement
- Eligible congestion drivers
- Modeling data

2022/2023 Long-Term Window Schedule (Year 2023)

Jan. – April
- Open long-term window
- Mid-cycle update

May – Sept.
Analysis of proposed solutions

Oct. – Nov.
TEAC reviews: first and second reads

JAN. APR. MAY AUG. SEPT. OCT. NOV. DEC.
2023

June – Aug.
Independent cost/ constructability review

Dec.
PJM Board approval of selected solutions

2022/2023 Long-Term Window B/C Ratio Method

Run PROMOD analysis with and without upgrade

Study years to simulate: Market Efficiency Projects are studied incrementally to RTEP projects.

RTEP Year – 4, RTEP Year, RTEP Year + 3, RTEP Year + 6

2022/2023 Window: 2023, 2027, 2029, 2033

Process PROMOD Hourly Output Files and calculate benefits

Hourly Files

- **UNT** file for hourly generation outputs
- **TRN** file for hourly net interchange
- **BUS** file for hourly bus/hub outputs
- **BS2** file for hourly bus/hub congestion component
- **ACT** file for hourly transactional unit outputs

Determine Market Efficiency Benefit to Cost Ratio (B/C Ratio)

Variables

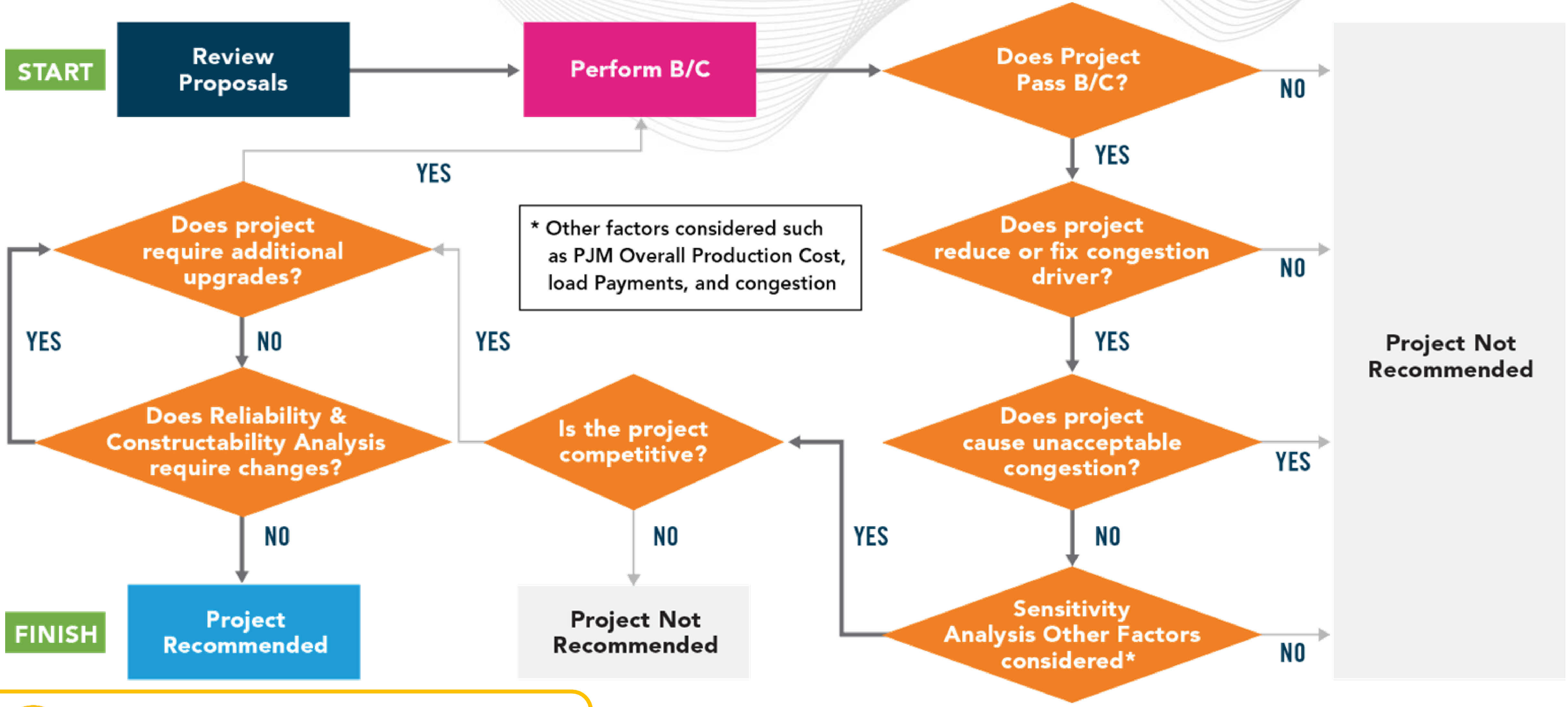
- PJM **Fixed Carrying Charge Rate** for Annual Revenue Requirement (Cost Component);
- PJM **Discount Rate** for NPV calculations (Benefits and Costs)

2022/2023 Long-Term Window Sensitivities

Sensitivity	Range
Load Sensitivity	Plus or Minus 2%
Gas Sensitivity	Plus or Minus 20% Henry Hub
FSA Sensitivity	Add all units with FSA or suspended ISA status

PJM reserves right to add sensitivities as necessary.

Market Efficiency Project Selection Flowchart*



* **Note:** For the purposes of training, diagram shows Energy Market proposals

Project Class	Cost Allocation: Market Efficiency Projects	Energy Market Benefit Determination
Regional Projects	50% Load Ratio Share and 50% to zones with decreased net load payments	**Energy Benefit:** 50% change in production costs + 50% change in net load payments (only zones with decrease in net load payments)
Lower Voltage Projects	100% to zones with decreased net load payments	**Energy Benefit:** 100% change in net load payments (only zones with decrease in net load payments)

* **Note:** For the purposes of training, we assume only Energy Market Benefits

Market Efficiency Re-evaluation Process

- Applies to Market Efficiency Projects approved during previous RTEP Windows
- Using the most recent Market Efficiency case available
- Projects already in-service, under construction or canceled are no longer required to be re-evaluated.
- Analysis performed individually, one project at a time
- Projects must continue to meet the B/C criterion of 1.25
- Re-evaluation process to be completed by the end of the year

Re-evaluation Process

Create a new base case by removing/reversing the topology related to the approved Market Efficiency Project

Measure the impact of adding back the approved Market Efficiency Project

Measure benefits for 15-year period starting with the RTEP date

For RPM projects also measure the capacity benefits

Calculate the new B/C ratios

Market Efficiency Acceleration Process

Acceleration Analysis Overview

Scope

Determine which reliability upgrades, if any, have an economic benefit if accelerated or modified

Study Years

As-Is and RTEP set of economic input assumptions used to study impacts of approved RTEP projects

Process

- Compare market congestion for near term vs. future topology
- Estimate economic impact of accelerating planned upgrades

Acceleration Analysis Process

- **Build** the AS-IS PROMOD model
  - Topology based on MMWG Series Year 1 power flow
  - Generation Expansion, Load Forecast, Fuel & Emissions Forecasts from the current Market Efficiency Base Case

- **Identify** previously approved RTEP reliability projects responsible for congestion reductions

Acceleration analysis results to be presented at the December TEAC

2022/23 Long-Term Window Registration Process

Market Efficiency RTEP Window Registration

Beginning in July 2020, all RTEP competitive proposals must be submitted through a new web-based Competitive Planner application.

Beginning in July 2020, all RTEP competitive proposals will be submitted through a new web based Competitive Planner application. Only transmission owners and developers who have received authorization to receive CEII information associated with the current window will be able to participate in the PJM competitive planning process.

Request Access to Competitive Planner

Only transmission owners and developers who have received authorization to receive CEII information associated with the current window will be able to participate in the PJM competitive planning process.

- **Register** for the 2022/23 RTEP Market Efficiency Window at PJM.com > Planning > [Competitive Planning Process]
- In the CEII Request form, write "***Access to the 2022/23 Long Term RTEP Window***" as the description of the information requested.
- All participants must register to access the data regardless of prior participation in the PJM Competitive Process.

RTEP Window Registration Screenshot

about pjm | training | committees & groups | planning | markets & operations | library

- Services & Requests
- Project Status & Cost Allocation
- Competitive Planning Process
  - Redacted Public Proposals for Current and Closed Windows
  - Pre-Qualification for Designated Entity Status
- RTEP Development
- Resource Adequacy Planning
- Planning Criteria
- Design, Engineering & Construction
- Interregional Planning

Home ▸ Planning ▸ Competitive Planning Process

Competitive Planning Process

Competitive Planner makes it easier for transmission owners and transmission developers to submit proposals through PJM's competitive transmission development process windows. It provides an interactive form that allows developers to provide information more easily and accurately, while also securely submitting that information to PJM from a single location.

Previously developers would need to fill out an Excel file that would then be uploaded securely.

PJM will announce in the Transmission Expansion Advisory Committee (TEAC) its intention to solicit competitive solutions to identified planning needs. The "windows" for submitting such solutions fit into three categories and follow the 18-month and 24-month planning cycles as described in Manual 14F.

Pre-Qualified Entities

While not a requirement to propose competitive projects, an entity must obtain Designated Entity status in order to construct, own, operate, maintain, and finance competitive planning projects. If your company hasn't been pre-qualified, apply for pre-qualification status.

Resources

Transmission Expansion Advisory Committee (TEAC)
Apply For Pre-Qualification Status
FERC Form 715 - FERC Guidelines For Diagram Requests
Manual 14F: Clean WEB | Clean PDF

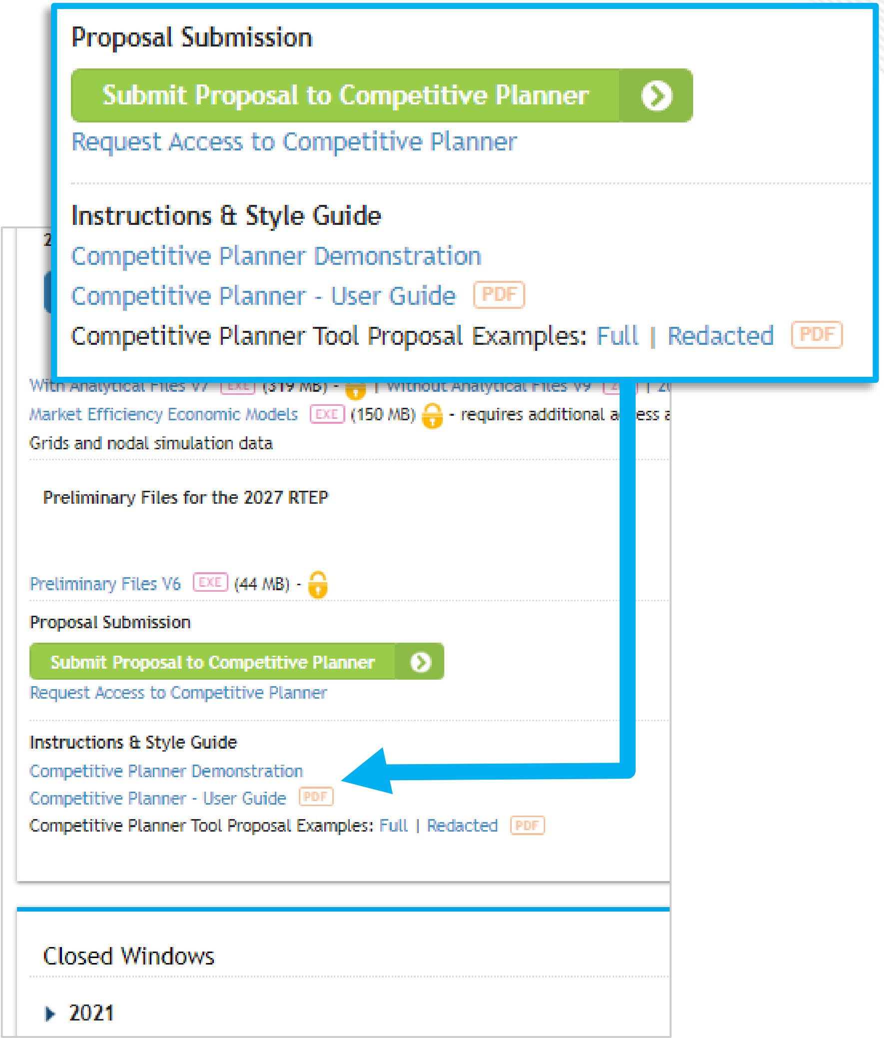
Planning Community

Training Video | User Guide PDF
Register for Community

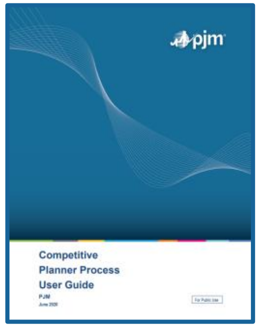
Planning Cycles

Window Type	What's Included	Duration (days)	Required In-Service Date (years)
Long Term	Reliability criteria violations, economic constraints, system conditions and public policy requirements	120	> 5

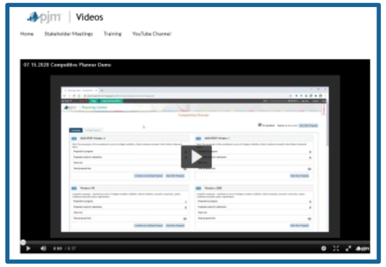
Competitive Planner Tool Training Materials



PJM has a Users Guide posted to the PJM website for the new Competitive Planner Tool:
PJM.com > Planning > Competitive Planning Process > Competitive Planner – User Guide



There is also a demonstration video posted to the PJM website showing how to use the new Competitive Planner Tool:
Videos.pjm.com > Competitive Planner Demo



PJM has also posted Examples of Competitive Planer proposals:
PJM.com > PJM.com > Planning > Competitive Planning Process > Competitive Planner Tool Proposal Examples: Full | Redacted

Appendix A
Example B/C Ratio Calculation

- Hypothetical project will be considered
- Energy benefits are calculated
- Both regional and low voltage benefits are determined

Project Benefits for Non-Simulated Years

RTEP Model year: 2027
Project In-service Year: 2027
PROMOD IV Simulation Years: 2023, 2027, 2030 & 2033

2023	Period 1	2027	Period 2	2030	Period 3	2033	Period 4

Period 1 benefits
2024 - 2026

$$2023\text{ Benefit} + \frac{(2027\text{ Benefit} - 2023\text{ Benefit})}{2027 - 2023}\text{ x }(\text{year} - 2023)$$

Period 2 benefits
2028 - 2029

$$2027\text{ Benefit} + \frac{(2030\text{ Benefit} - 2027\text{ Benefit})}{2030 - 2027}\text{ x }(\text{year} - 2027)$$

Period 3 benefits
2031 - 2032

$$2030\text{ Benefit} + \frac{(2033\text{ Benefit} - 2030\text{ Benefit})}{2033 - 2030}\text{ x }(\text{year} - 2030)$$

Period 4 benefits

Excel Formula: trend (known y-values, known x-values, new x’s)

Selecting Zones Based on Net Load Payment

Project in-service date: 2027

- Therefore the benefits are evaluated between 2027 and 2041, the first 15 years of in-service life
- Zones 1, 2 and 4 all have Net Load Payment benefits with an NPV > 0 for the 15 year analysis period. These zones will be included in the total system benefit
- The Net Present Value of Net Load Payment Benefits in Zone 3 do not exceed zero for the 15-year analysis period. This zone will be excluded from the total system benefit calculation

Low Voltage Project Net Load Payment Benefit

Zone 1 + Zone 2 + Zone 4 = $217.56 Million

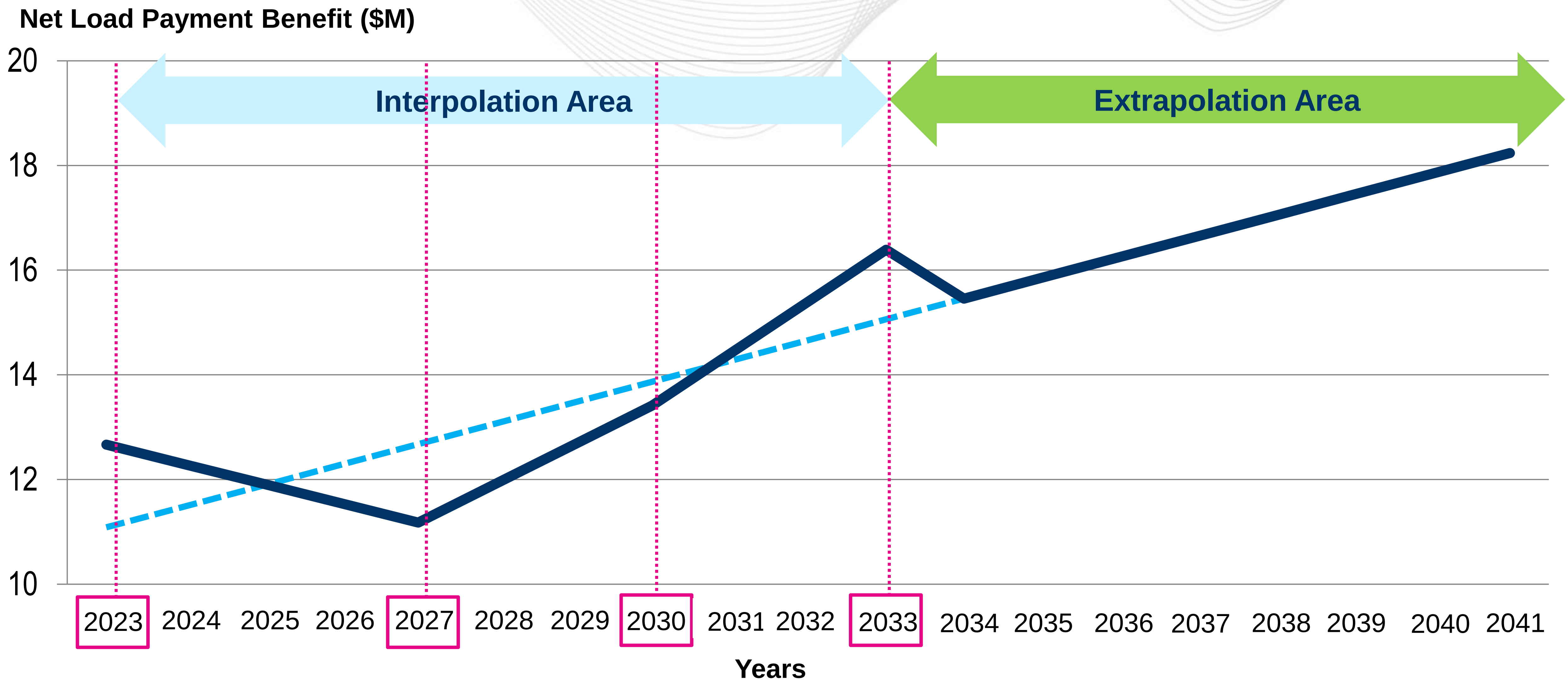
Regional Project Net Load Payment Benefit

50% (Zone 1 + Zone 2 + Zone 4) = $108.78 Million

ISD

Year	Zone 1	Zone 2	Zone 3	Zone 4
2023	$12.67	$3.00	$0.50	$5.00
2024	$12.29	$2.50	$0.40	$5.30
2025	$11.92	$2.00	$0.30	$5.50
2026	$11.55	$1.50	$0.20	$5.80
2027	$11.18	$1.00	$0.10	$6.00
2028	$11.92	$1.30	($0.30)	$6.70
2029	$12.67	$1.70	($0.60)	$7.30
2030	$13.41	$2.00	($1.00)	$8.00
2031	$14.40	$2.20	($1.70)	$7.70
2032	$15.40	$2.30	($2.30)	$7.30
2033	$16.39	$2.50	($3.00)	$7.00
2034	$15.46	$2.00	($2.80)	$7.90
2035	$15.85	$1.90	($3.20)	$8.20
2036	$16.25	$1.90	($3.50)	$8.40
2037	$16.65	$1.90	($3.80)	$8.70
2038	$17.05	$1.84	($4.19)	$8.90
2039	$17.44	$1.81	($4.53)	$9.15
2040	$17.84	$1.78	($4.87)	$9.40
2041	*$18.24*	*$1.75*	*($5.22)*	*$9.64*
NPV (Millions)	**$131.90**	**$16.31**	**($20.02)**	**$69.34**

Example Zonal Net Load Payment Benefits



System Adjusted Production Cost Benefits

- The Project is not in-service until 2025. Therefore the benefits are evaluated between 2027 and 2041

- **NPV Adjusted Production Cost Benefit =** NPV(7.26%, Adjusted Production Cost Savings)

- **Regional Adjusted Production Cost Benefits =** 50% x $121.2 Million =$60.61

Year	Net Adjusted Production Cost Benefit
2023	$8.00
2024	$8.50
2025	$9.00
2026	$9.50
ISD *2027*	$10.00
2028	$10.70
2029	$11.30
2030	$12.00
2031	$12.70
2032	$13.30
2033	$14.00
2034	$14.50
2035	$15.10
2036	$15.70
2037	$16.30
2038	$16.88
2039	$17.48
2040	$18.08
2041	$18.68
NPV (Millions)	**$121.2**

Metric Comparison

Regional Method

Total Energy Market Benefits =
Load Payment Benefit x 50% + Production Cost Benefit x 50%

Total Benefits = \$108.78 Million + \$60.61 Million
= ***\$169.38 Million***

Low Voltage Method

Total Benefits =
100% Load Payment Benefit
= ***\$217.56 Million***

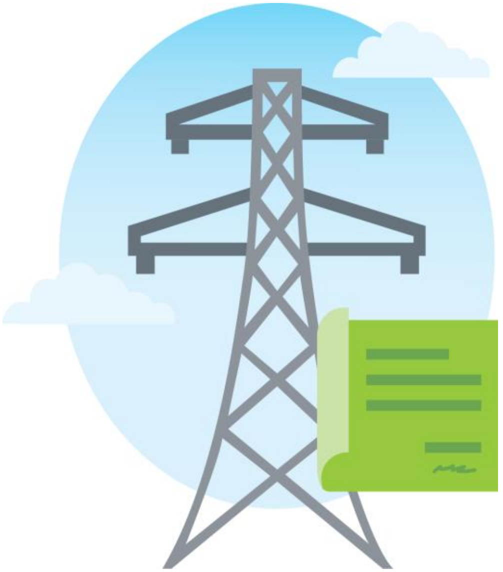
Appendix B
Auction Revenue Right (ARR) Example

Auction Revenue Right (ARR) Modeling

- **ARRs are entitlements allocated annually to Firm/Network Transmission Service Customers** that entitle the holder to receive an allocation of the revenues from the annual Financial Transmission Right (FTR) Auction

- ARRS provide a hedge against congestion incurred between where loads are sunk on the power system versus the supply sources that serve the loads

- Most recent cleared MWs from the ARR annual auction are modeled in the Market Efficiency case

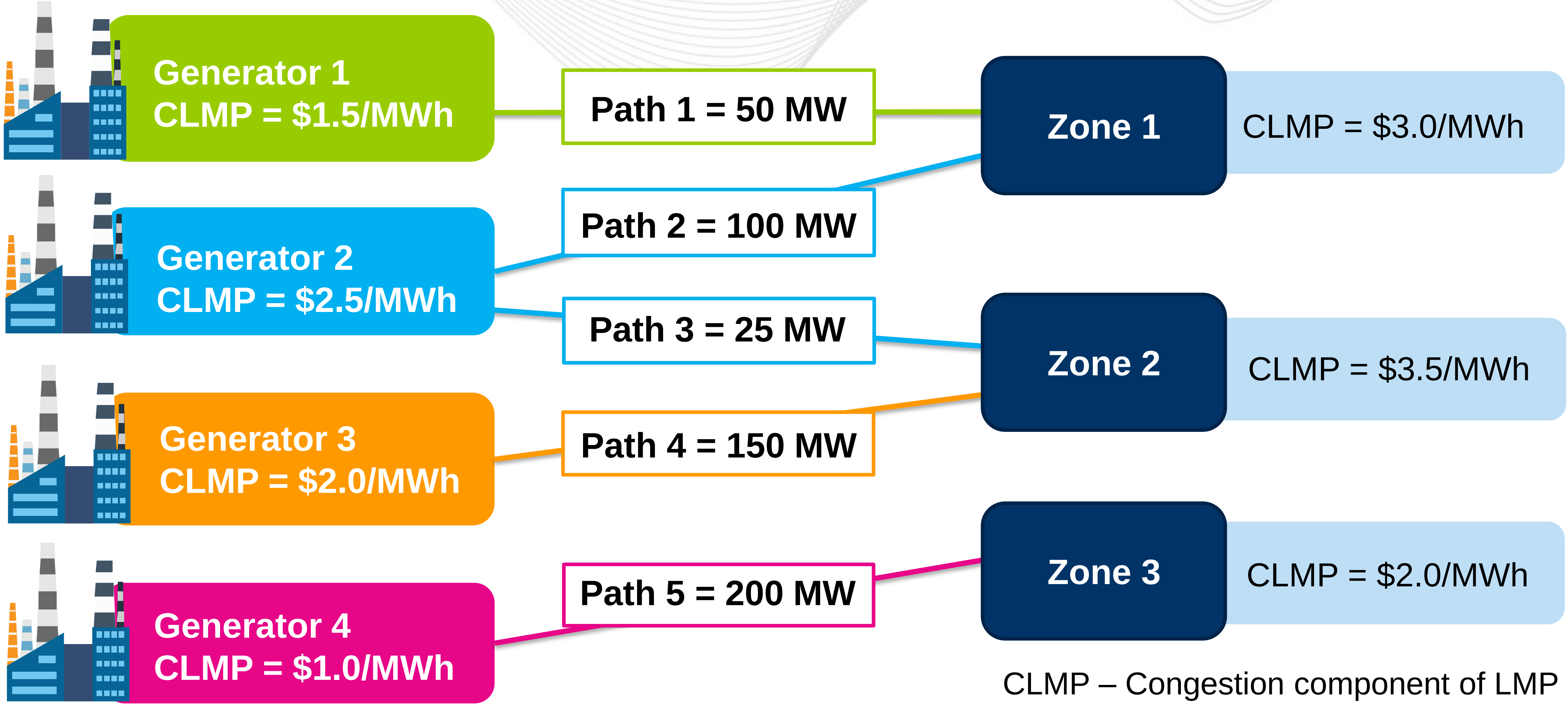


Modeling Objective

- To determine the value of ARRs through future year SCED modeling.
- Project benefits to LSE’s is therefore the net of the change in load payments due to LMP reductions and the change in value of the ARR’s held by the LSE

What does it mean: The project benefits to LSE’s are limited to the unhedged congestion reductions

Auction Revenue Right Example



CLMP – Congestion component of LMP

Auction Revenue Right Valuation

Path	Source	Source CLMP	Sink	Sink CLMP	Cleared Path MW	ARR Value
1	Generator 1	$1.5	Zone 1	$3.0	50	$657,000
2	Generator 2	$2.5	Zone 1	$3.0	100	$438,000
3		$2.5	Zone 2	$3.5	25	$219,000
4	Generator 3	$2.0	Zone 2	$3.5	150	$1,971,000
5	Generator 4	$1.0	Zone 3	$2.0	200	$1,752,000

Path Value = $(CLMP_{sink} – CLMP_{source})$ x Cleared MW x 8,760

Zone 1 ARR Valuation = Path 1 Value + Path 2 Value = $1.095 Million

Zone 2 ARR Valuation = Path 3 Value + Path 4 Value = $2.19 Million

Zone 3 ARR Valuation = Path 5 value = $1.752 Million

Appendix C – Glossary

Terms and Acronyms

B/C Ratio	Benefit-to-Cost Ratio
EIA	U.S. Energy Information Administration
EPA CEMS	U. S. Environmental Protection Agency Continuous Emission Monitoring System
FCR	Fixed Carrying Charge Rate
FSA Unit	Facility Study Agreement
ISA Unit	Interconnection Service Agreement
LMP	Local Marginal Price
NLP	Net Load Payment
NPV	Net Present Value

Terms and Acronyms

NYMEX	New York Mercantile Exchange
M2M	Market-to-Market Flowgate
MMWG	Multi-Regional Modeling Working Group
PV	Present Value
RGGI	Regional Greenhouse Gas Initiative
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
TEAC	Transmission Expansion Advisory Committee

- **Change in Total Adjusted Energy Production Cost**

  Calculated as difference in total Adjusted Production Costs without and with the enhancement or expansion

- **Change in Load Energy Payment**
  - Calculated as difference between the Net Load Payments without and with the economic-based enhancement or expansion.
  - Only zones that show a decrease will be considered in determining the Change in Load Energy Payments

Reliability Pricing Model (RPM) Benefits – Definitions

- **Change in Total System Capacity Cost**

  Calculated as the difference between the sum of the megawatts that are estimated to be cleared in the Base Residual Auction under PJM's Reliability Pricing Model capacity construct times the prices that are estimated to be contained in the offers for each such cleared megawatt (times the number of days in the study year) without and with the economic-based enhancement or expansion

- **Change in Load Capacity Payment**
  - Calculated as the sum of the estimated zonal load megawatts in each PJM transmission zone times the estimated Final Zonal Capacity Prices (payments paid by load in each transmission zone) for capacity under the Reliability Pricing Model construct (times the number of days in the study year) minus the value of Capacity Transfer Rights for each PJM transmission zone without and with the economic-based enhancement or expansion
  - Only PJM transmission zones that show a decrease will be considered in determining the Change in Load Capacity Payment

Appendix D – Operating Agreement & Manual References

Additional Resources

PJM Market Efficiency home page:
PJM.com > Planning > RTEP Development > Market Efficiency

PJM Manual 14B - PJM Region Transmission Planning Process:
PJM.com > Library > Manuals > Manual 14B

PJM Manual 14F - Competitive Planning Process:
PJM.com > Library > Manuals > Manual 14F

PJM Operating Agreement, Schedule 6, Section 1.5.:
PJM.com > Library > Governing Documents > Operating Agreement (OA)

PJM Market Efficiency Example B/C Ratio Calculation:
http://www.pjm.com/~/media/committees-groups/committees/pc/20161215/20161215-item-15c-pjm-market-efficiency-overview-example-bc-ratio-calculation.ashx