RTEP Overview

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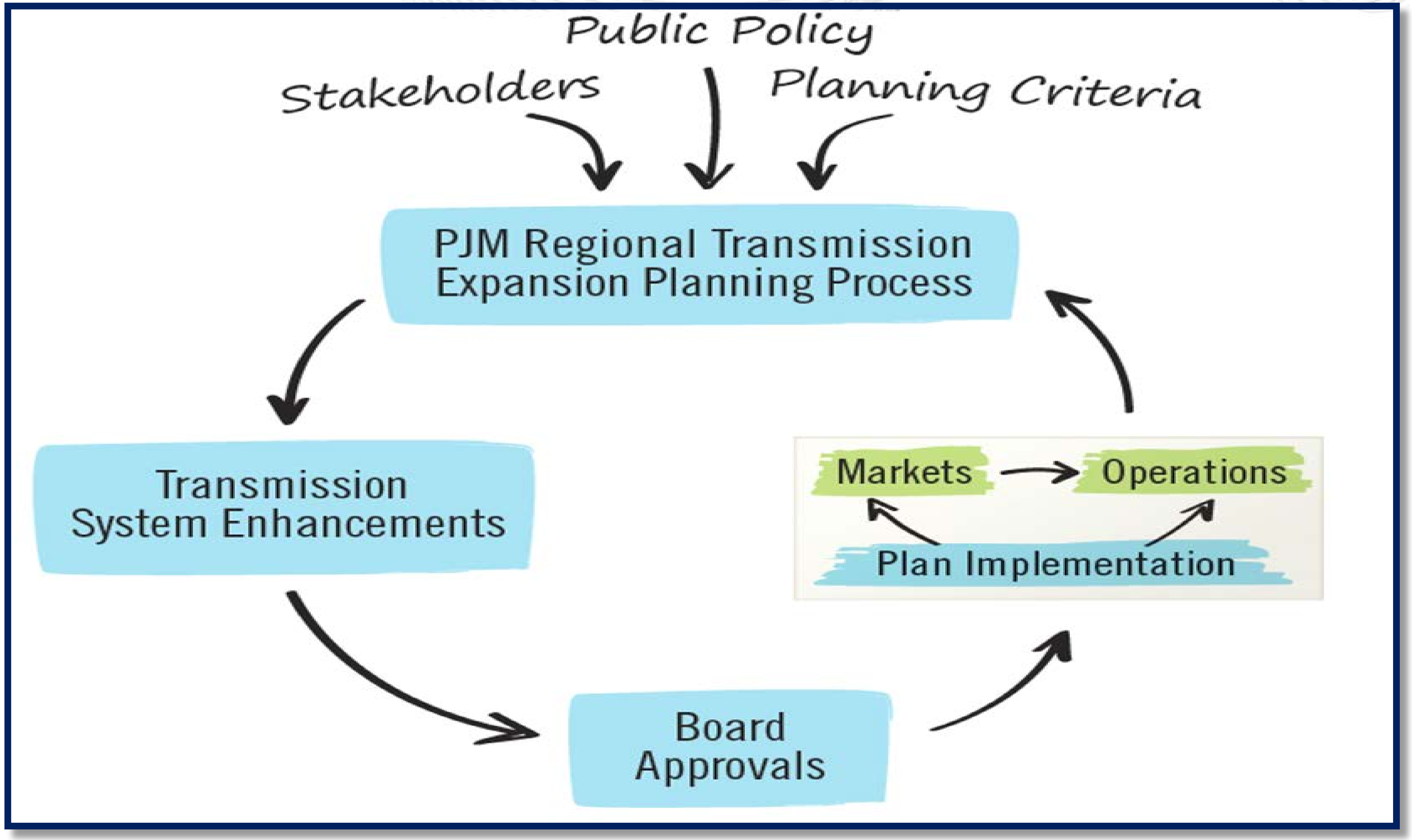
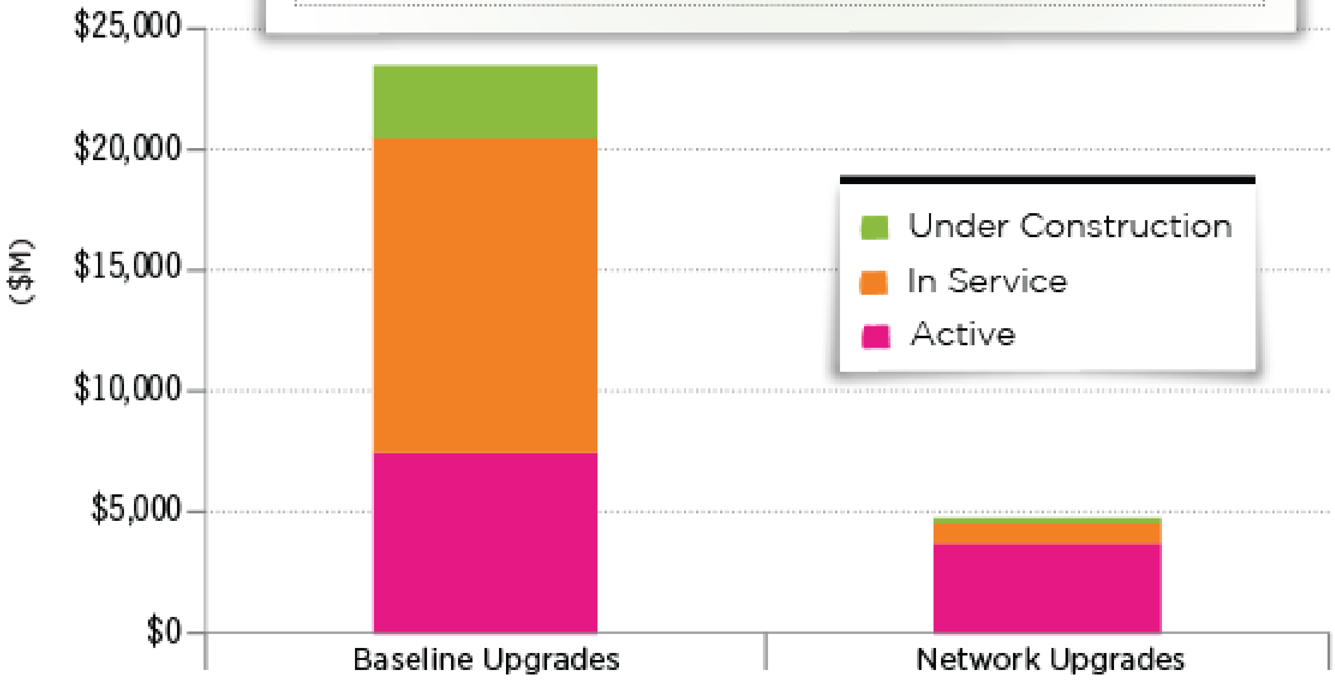
RTEP Process Overview

RTEP Process - Overview



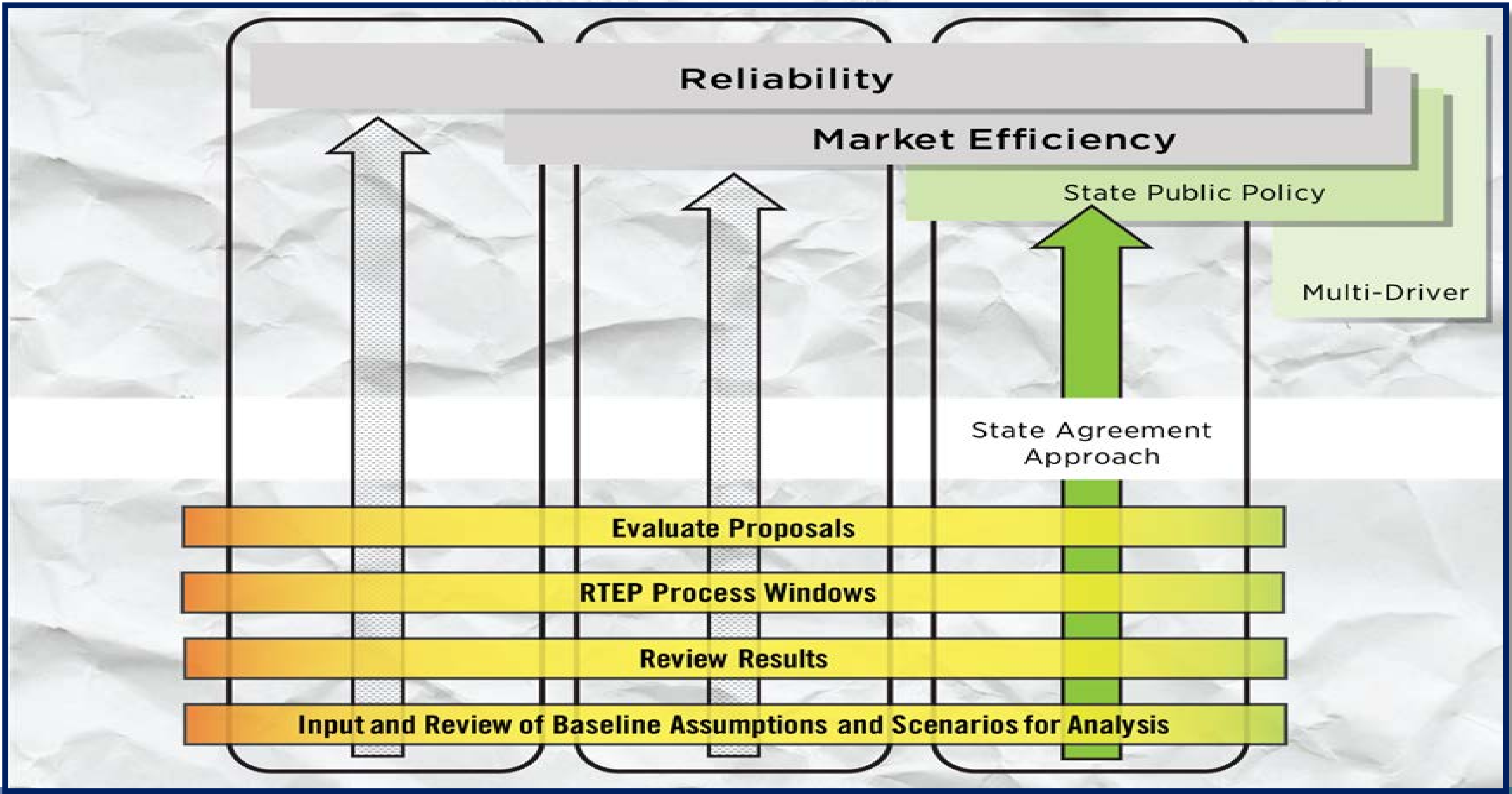
Approved RTEP Upgrades – December 31, 2015

$ Millions	Active	In Service	Under Construction	Total
Baseline Upgrades	7,426.9	13,098.8	2,982.8	23,508.5
Network Upgrades	3,662.3	848.5	258.9	4,769.7
Total	11,089.2	13,947.3	3,241.7	28,278.2

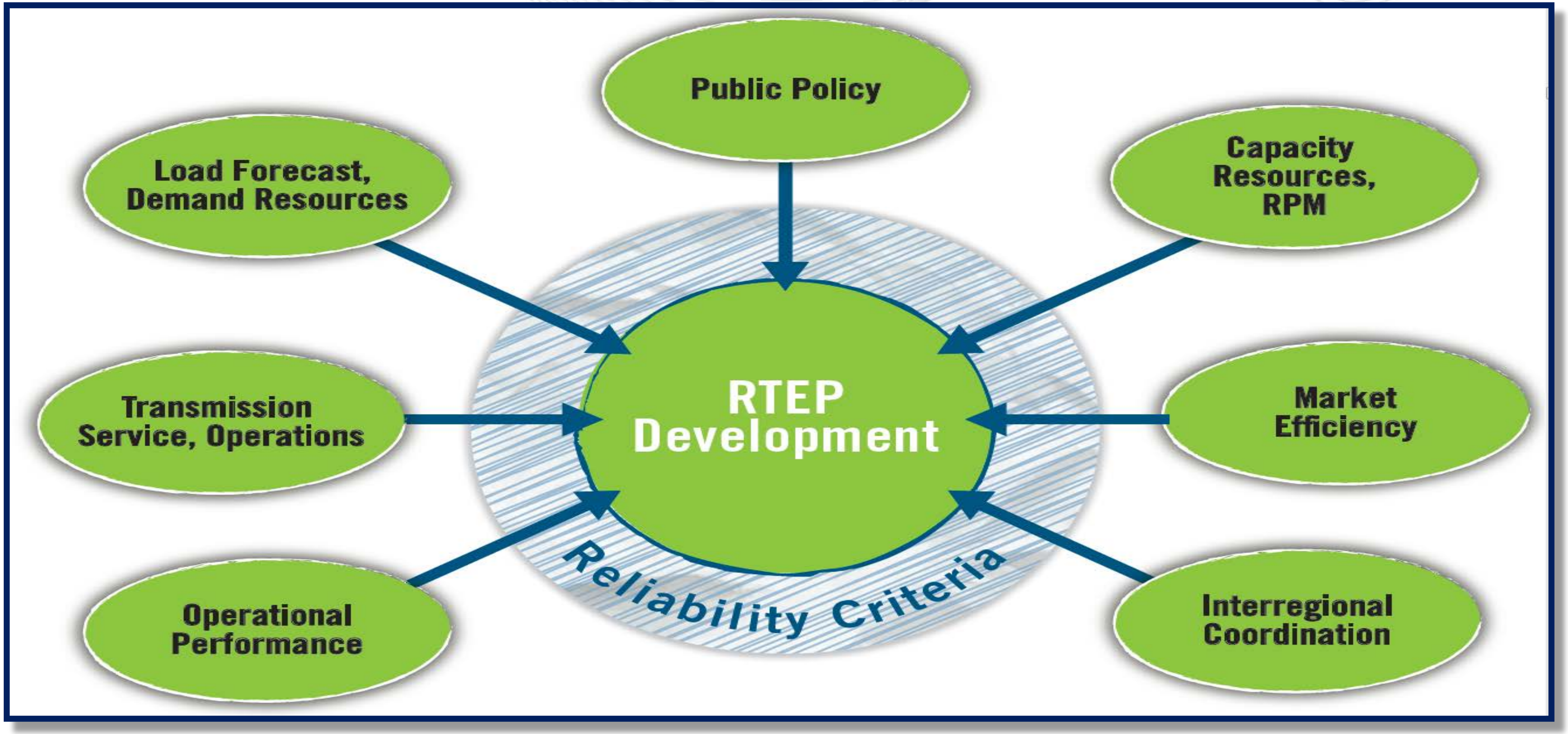


Note these are all capital dollars.

RTEP Process Decision-Making



System Expansion Drivers



RTEP Process Stakeholder Participation

- RTEP process is open and transparent
- Open
  - Members
  - Regulatory Agencies (Federal or State) including Consumber Advocates
  - “any other interested parties”
- Transparent
  - On-line information
  - Regular stakeholder meetings and communications

3 Buckets

- Baseline – upgrades required to keep the system compliant with reliability criteria, market efficiency criteria, public policy and operational performance

- Network – “but for” upgrades required for New Service Customers

- Supplemental – Changes to the transmission system that are not required to satisfy reliability, market efficiency, operational performance or public policy criteria

RTEP Process Baseline Concept

RTEP Process Analysis → RTEP Process Window → PJM Evaluation of Proposals → Recommendation to the Board

- ✓ FERC-approved
- ✓ 15 year planning horizon
- ✓ 12 month and 24 month cycle
- ✓ Comprehensive and Holistic
  - Multi-driver: Reliability, Market Efficiency, Public Policy
- ✓ Open, transparent, collaborative stakeholder process
- ✓ Order No. 1000 compliant

RTEP Study Scope

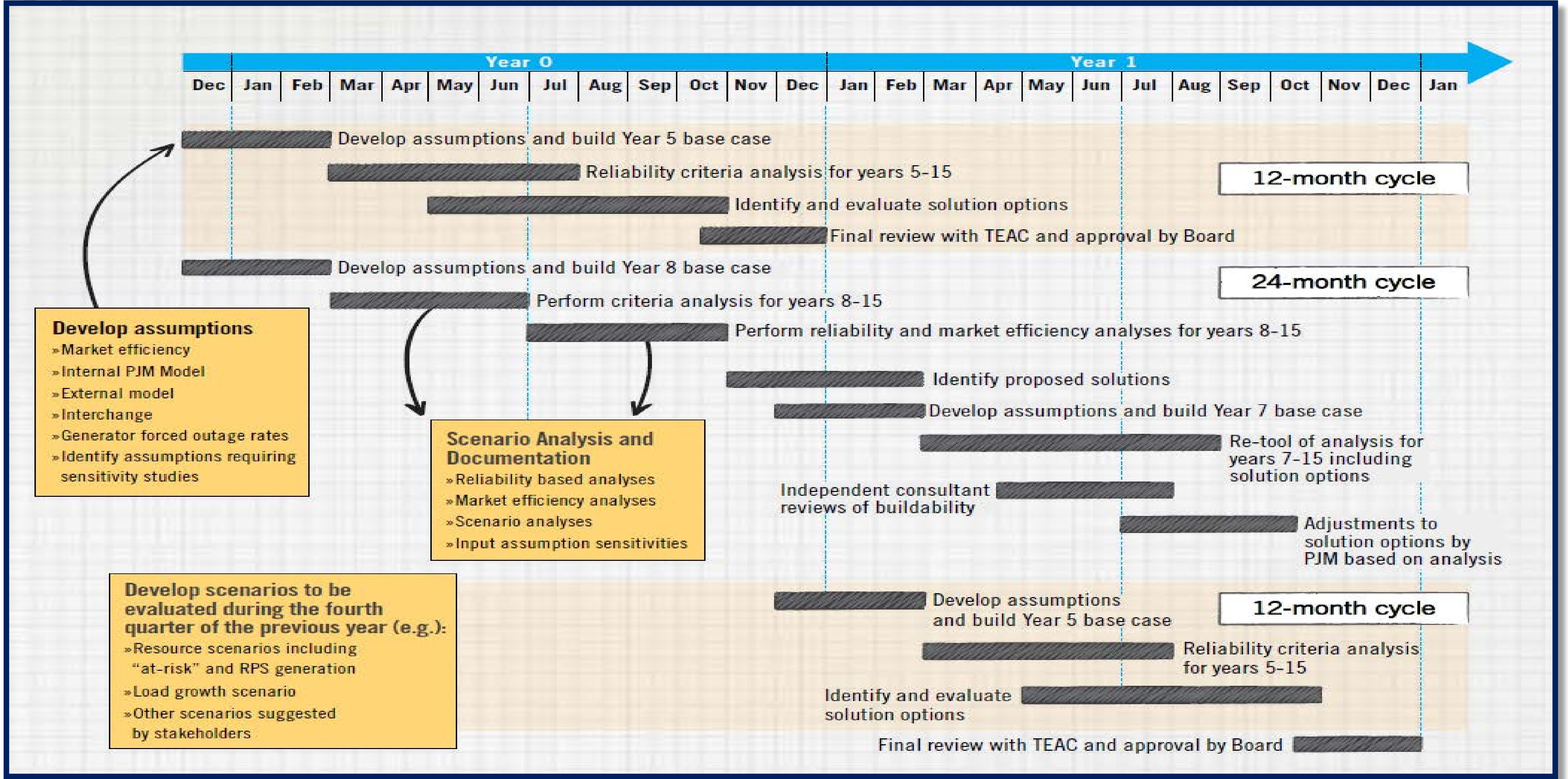
Baseline

- ✓ Identify violations for multiple deliverability areas, or multiple or severe violations clustered in one specific area.
- ✓ Permits PJM to assess larger-scale, longer lead-time solutions
- ✓ RTEP process analyses:
  - – Normal system, single and multiple contingency analysis.
  - – Load deliverability and generator deliverability test conditions

As well as…

- ✓ New service studies (e.g., generator interconnection)
- ✓ Market efficiency studies
- ✓ Scenario studies
- ✓ Interregional analyses

RTEP Process Timeline

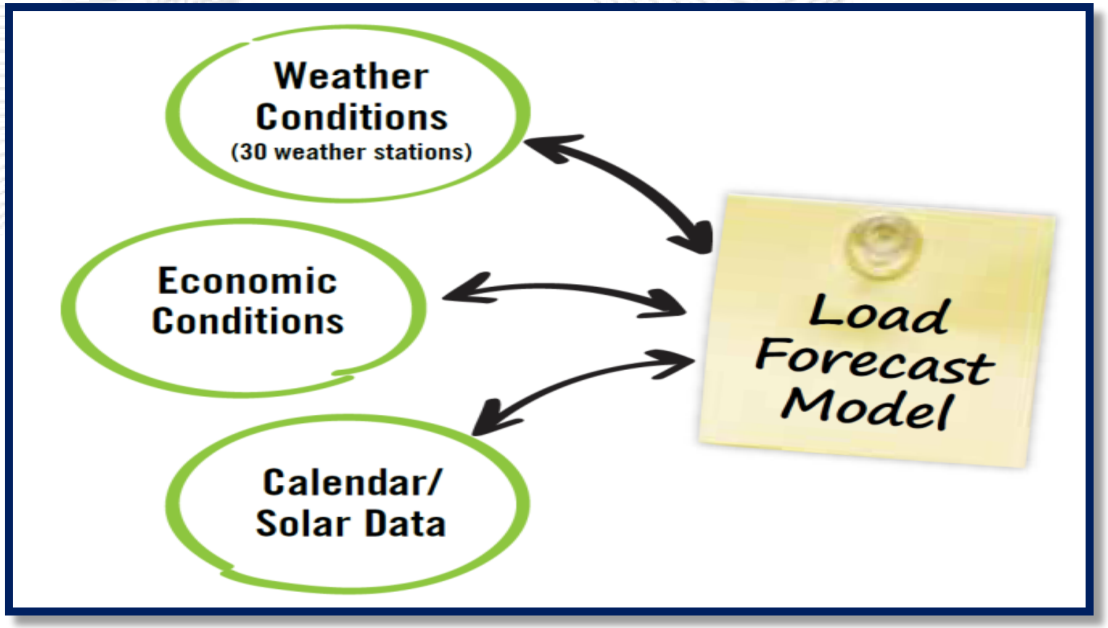


Stakeholder Forums

- **PJM Planning Committee**
  http://www.pjm.com/committees-and-groups/committees/pc.aspx
- **Transmission Expansion Advisory Committee (TEAC)**
  http://www.pjm.com/committees-and-groups/committees/teac.aspx
- **PJM Mid-Atlantic Sub-Regional RTEP Committee**
  http://www.pjm.com/committeesand-groups/committees/srrtep-ma.aspx
- **PJM Western Sub-Regional RTEP Committee**
  http://www.pjm.com/committees-and-groups/committees/ssrtep-w.aspx
- **PJM Southern Sub-Regional RTEP Committee**
  http://www.pjm.com/committees-and-groups/committees/ssrtep-s.aspx
- **Independent State Agencies Committee (ISAC)**
  http://pjm.com/committees-and-groups/isac.aspx

Input Assumptions

Load Forecast Model



Weather Conditions

- ✓ Weighted average temperature, humidity & wind speed
- ✓ 30+ weather stations across PJM.

Economic Conditions

- ✓ Gross Domestic Product,
- ✓ Gross Metropolitan Product,
- ✓ Real personal income,
- ✓ Population,
- ✓ Households,
- ✓ Non-manufacturing employment

Calendar / Solar Data

- ✓ Day of week
- ✓ Month
- ✓ Weekends / Holidays
- ✓ Minutes of Daylight

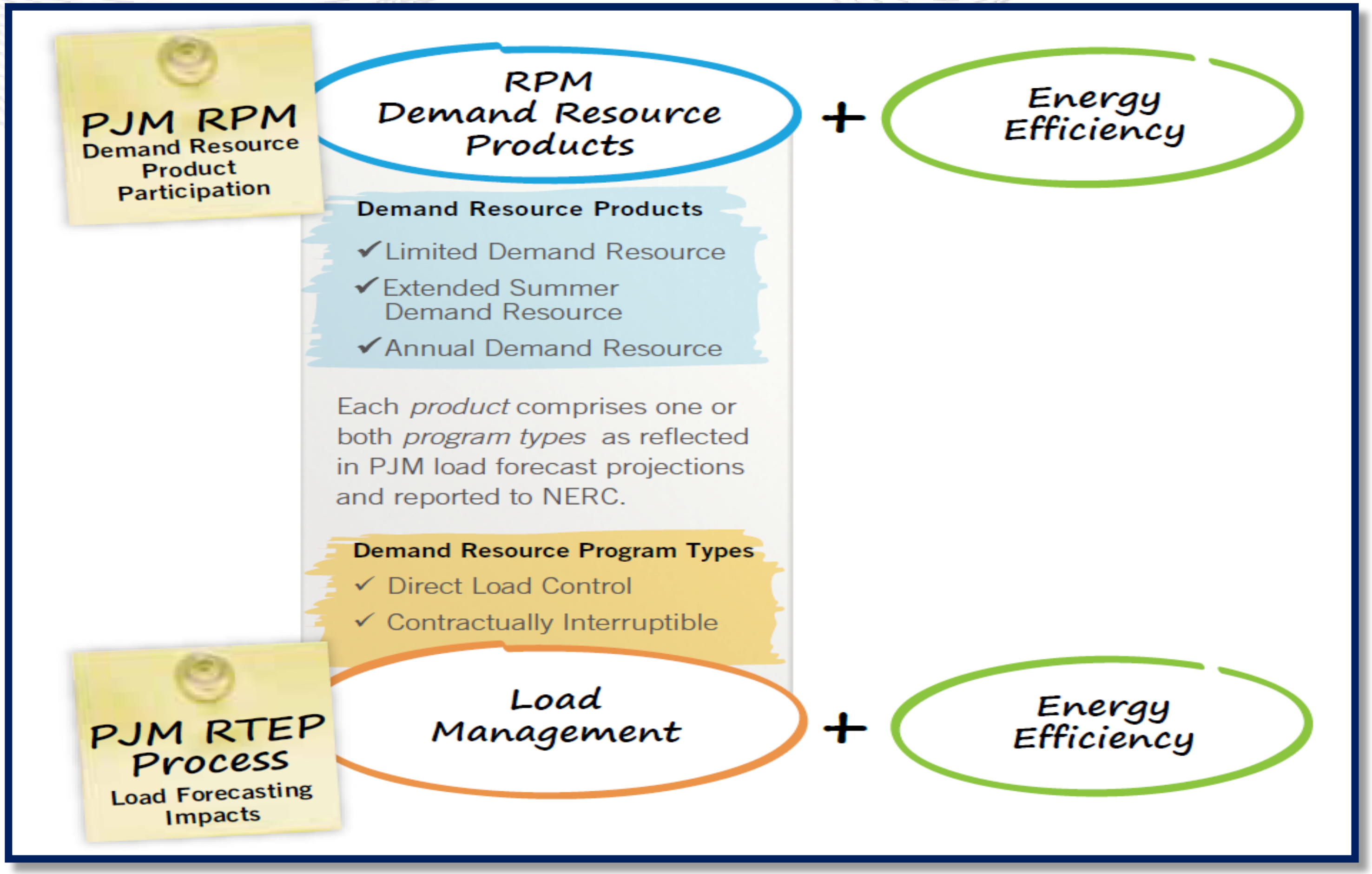
Translating Zonal Load Forecasts to Power Flow Bus Loads

- ✓ PJM assigns zonal load from January forecast to individual zonal buses according to ratios of each bus load to total zonal load.

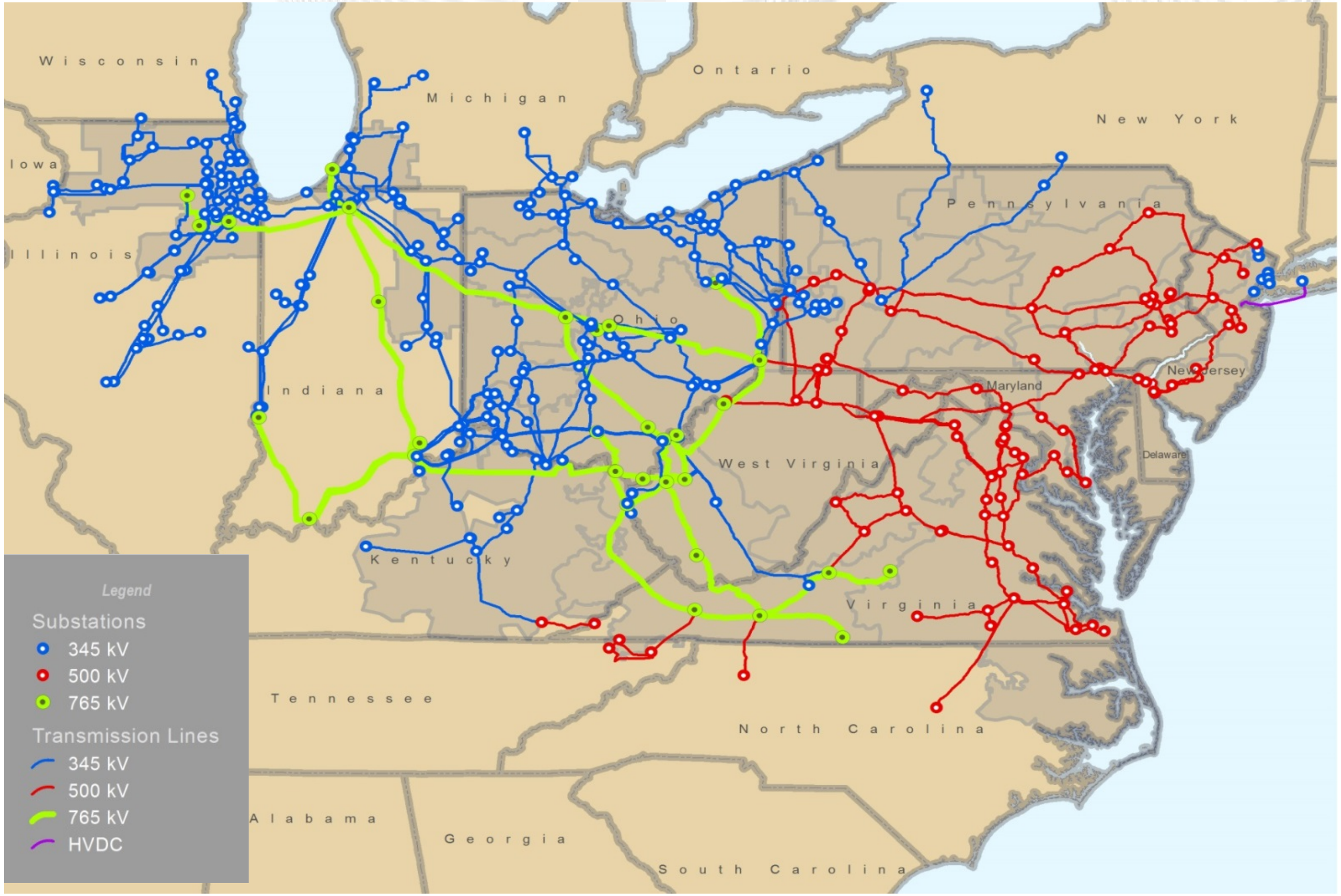
- ✓ Ratios are supplied by each transmission owner to PJM.

Demand Resources and Energy Efficiency

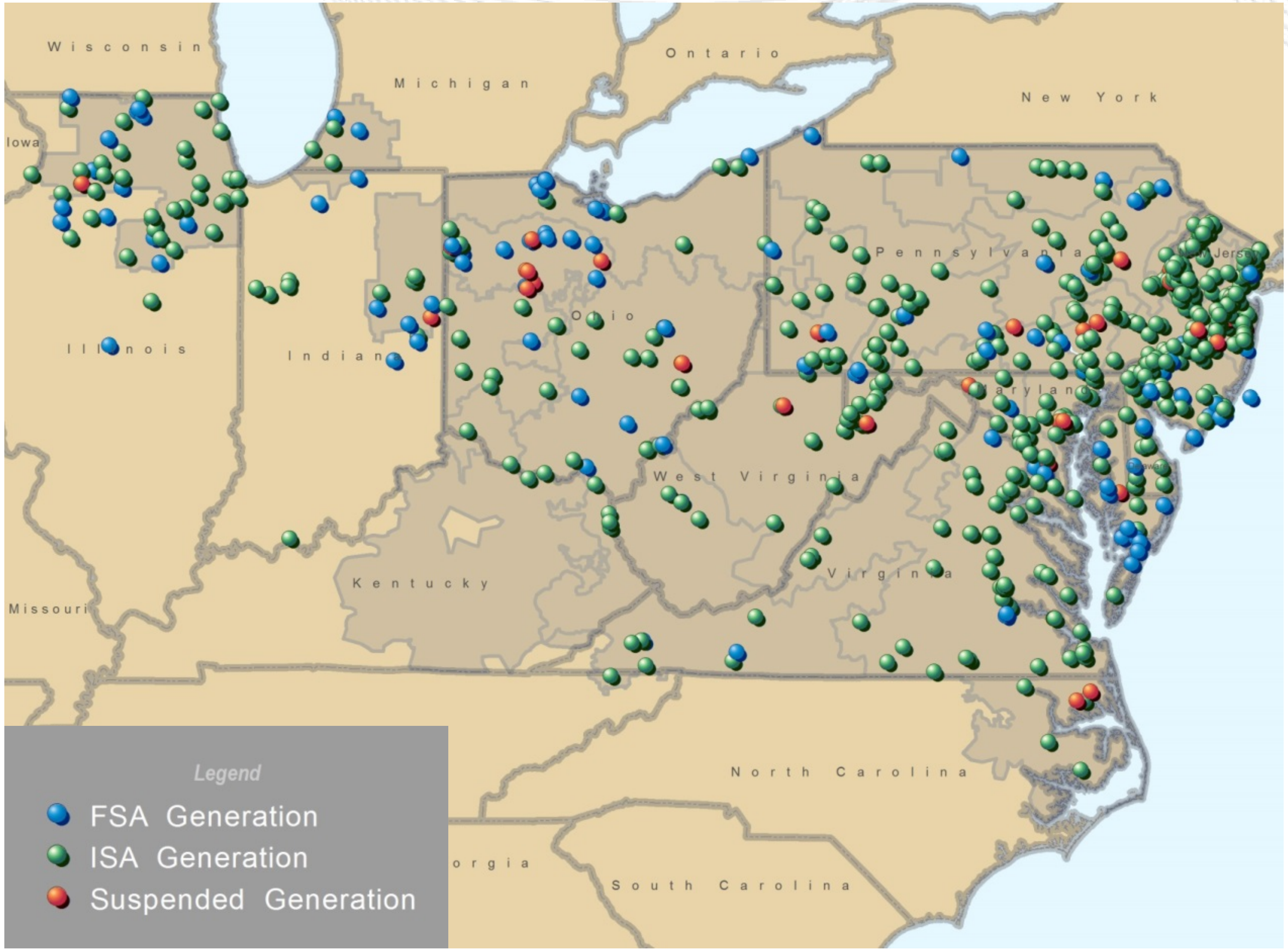
- ✓ Existing *and* planned demand resources may participate in RPM Auctions, provided the resource resides in a party's portfolio for the duration of the delivery year.
- ✓ Can defer the need for new generation and transmission resources.



Assumptions - Topology



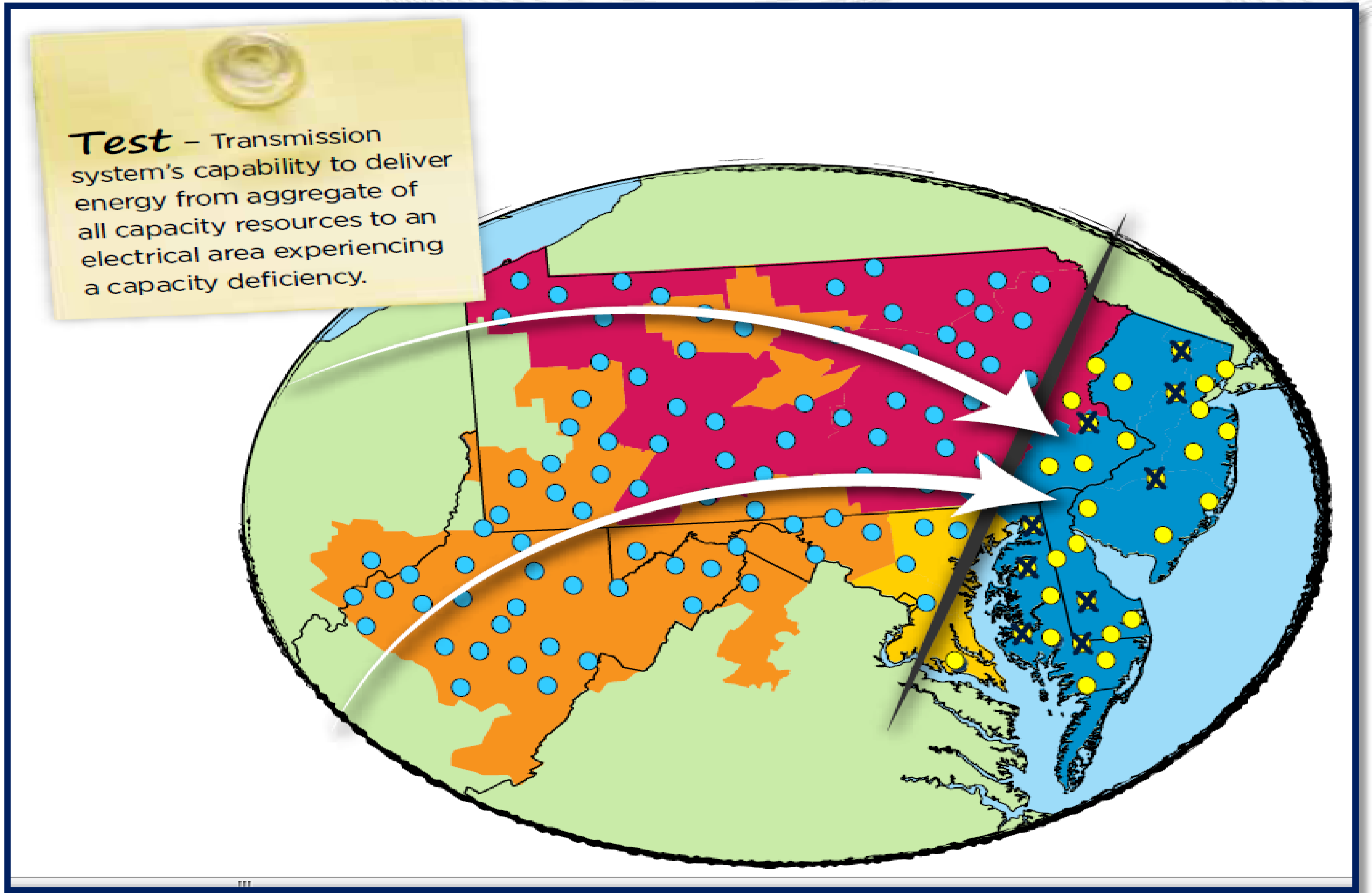
Generation Assumptions



RTEP Criteria

Load Deliverability Test

- ✓ Transmission system's capability to deliver energy from aggregate of all capacity resources to an electrical area experiencing a capacity deficiency
- ✓ Test failure…load is "bottled" inside a defined area; sufficient capacity cannot be "delivered" to serve load as a result of limiting transmission constraints
- ✓ Maintain CETO in defined area to achieve LOLE of 1-event-in-25 years…import capability needed to keep lights on with sufficient generating capacity…with all its size diversity and outage characteristics…probabilistic techniques
- ✓ Area tested for its expected import capability up to established transmission facility limits…CETL…how much an area can actually be expected to import
- ✓ **If CETL < CETO, test fails, additional transmission capability is needed**


Test – Transmission system's capability to deliver energy from aggregate of all capacity resources to an electrical area experiencing a capacity deficiency.

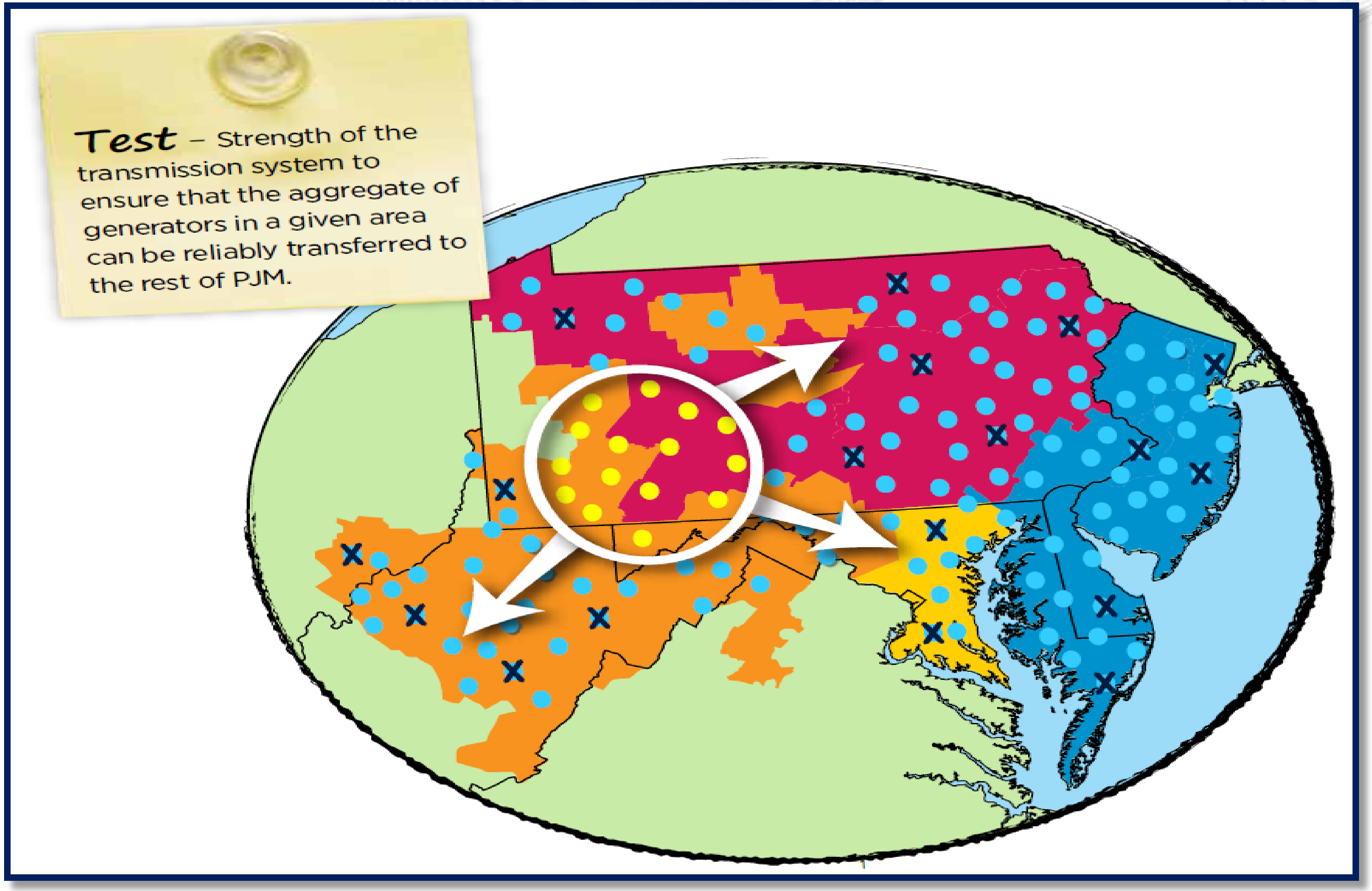
Generator Deliverability Test

- ✓ Strength of the transmission system to ensure that the aggregate of generators in a given area can be reliably transferred to the rest of PJM.

- ✓ Test determines if transmission limits exist that prevent generation in a defined area to be exported to the rest of PJM … is generation “bottled” or not.

- ✓ Also performed for each queued generator interconnection request at System Impact Study step.

Generator Deliverability Test



NERC Category C3 / “n-1-1” Analysis

Study Parameters

- ✓ 50/50 non-diversified case
- ✓ Single contingencies
- ✓ Both thermal and voltage limits

Run N-1 → System Adjustments → Run N-1-1 → System Adjustments → Review Results

Light Load Analysis

- ✓ Below 50 percent of summer peak in some TO zones
- ✓ Operational challenges
  - Low demand generation dispatch differs markedly from peak
  - Capacitive effects of lightly loaded transmission lines
  - Intermittent source output
  - Thermal overloads, high voltage events
- ✓ 2010 creation and approval of new light load reliability criteria
- ✓ 2011 first implemented and benchmarked in RTEP process
  - Baseline analysis
  - Queued interconnection request studies
- ✓ Overall, ensure transmission capable of delivering generating capacity under light load conditions
- ✓ Similar procedure to Generator Deliverability study
- ✓ Similar procedure to Common Mode Voltage Study

Winter Peak Study Summary

1. Winter Generator Deliverability/Common Mode Outage test
   - The ramping limit for generators of all fuel types will be 100% including wind
     - Consider a lower ramping limit for solar
   - Contingencies: NERC Category A, B, C (except N-1-1) or P0, P1, P2, P4, P5 and P7 (for the new TPL-001-4)
   - Annual DR
2. Winter Load Deliverability test
   - Winter CETO
   - Annual DR
   - 27 LDAs
   - Contingencies: NERC Category A, B
3. N-1 thermal, voltage
   - Contingencies: NERC Category A, B, C (except N-1-1) or P0, P1, P2, P4, P5 and P7 (for the new TPL-001-4)
4. N-1-1 thermal and voltage
   - Contingencies - (NERC TPL-001-4 P3 and P6)

- Overall Assumptions
  - Monitor all PJM BES and lower voltage BES and market monitored facilities
  - Currently, 30 Gas contingencies (TPL-001-4 Extreme Event) that results in 1000MW or more of generation loss including pipeline outage or temperature threshold contingencies will be evaluated in the tests above

Transmission Owner Criteria

- Per Schedule 6 of the Operating Agreement, the RTEP must conform with applicable reliability criteria including transmission owner FERC filed criteria in their Form 715 submittals

- In general, TO criteria includes: different ways to establish “critical system conditions,” defines applicable ratings for certain conditions

- Applicable to all voltage levels

- Some include other categories such as end-of-life criteria or storm hardening

- Criteria is posted on the PJM website at the following link: http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx

Short Circuit Analysis

- ✓ Fault or short circuit currents cause high thermal and mechanical stresses on power system equipment

- ✓ Circuit breakers clear faults to restore system to a stable operating point and to prevent equipment damage

- ✓ Analysis ensures each circuit breaker is rated sufficiently to interrupt system fault currents.

System Stability Studies

- ✓ Four-tiered analysis
  - Ensure BES Stability
  - Compliance with NERC TPL standards
  - System contingencies of reasonable probability consistent with standards.

1. *PJM Annual System-Wide Analysis:*
   - Transient stability analysis for 1/3 of network each year
   - Includes light load analysis (most challenging from stability perspective)

2. *Interconnection Request System Impact Studies*:
   - Queued generation additions
   - Transient stability analysis between new generator and existing BES

Stability Studies (continued)

3. *Operational Performance Issues*
   - Transient stability for topology changes
   - Areas with known, limited transient stability margin.
   - Frequently driven by real-time system conditions, events
4. *NERC Category C3 – "N-1-1"*
   - Single line to ground (SLG) or 3-phase fault with normal clearing, manual system adjustments, followed by another SLG or 3-phase fault with normal clearing.
   - Manual adjustments after first (N-1) contingency to relieve thermal or voltage violations to prepare for second (N-1-1) contingency.
   - First (N-1) contingency applied to pre-disturbance base case.
   - If system stable, new operating point established, manual adjustments made if necessary, then stability monitored following second (N-1-1) single contingency.

NERC Planning Criteria Compliance

Standard	Category	Contingencies
TPL-001	A	All facilities in service
TPL-002	B	Fault with normal clearing – Loss of all facilities associated with a single contingency
TPL-003	C1	Bus section faults
	C2	Breaker failure
	C3	Fault with normal clearing followed by re-dispatch followed by a second fault with normal clearing (N-1-1 Contingency)
	C5	Multiple circuit tower line
TPL-004	D	Extreme events

- NERC planning standard TPL-001-4 formally by FERC October 2013.
- January 1, 2016 effective date.

Steady-State Analysis	NERC TPL-001, TPL-002, TPL-003	NERC TPL-001-4
Basecase N-0 - No Contingency Analysis	Category A	P0
Basecase N-1 - Single Contingency Analysis	Category B1, B2, B3	P1
Basecase N-2 - Multiple Contingency Analysis	Category C1, C2, C5	P2, P4, P5, P7
N-1-1 Analysis	Category C3	P3, P6
Generator Deliverability	Category A, B1, B2, B3	P0, P1
Common Mode Outage Procedure	Category C1, C2, C5	P2, P4, P5, P7
Load Deliverability	Category A, B1, B2, B3	P0, P1
Light Load Reliability Criteria	Category B1, B2, B3	P1, P2, P4, P5, P7

Simultaneous Feasibility Test (SFT)

- ✓ Test to ensure that all subscribed transmission entitlements are within the capability of the existing transmission system

- ✓ Network and firm point-to-point transmission service reservations – equal to zonal load – modeled under expected network topology

- ✓ ARRs modeled from generation/source point to load/sink point

- ✓ DC power flow analysis; ‘n-1’ criteria test; if a violation occurs in any of 10 years, PJM develops an RTEP solution

Market Efficiency Analysis - Scope

- ✓ Conduct market simulations identify congestion in future years
  - Production cost tool
  - TEAC and Board reviewed input parameters
  - Hourly security-constrained generation commitment and dispatch
  - Year 1, Year 5, Year 8, Year 11, Year 15
- ✓ Identify transmission enhancement plans that may realize economic benefit by mitigating congestion
  - Accelerate existing reliability-justified enhancement plans
  - Solutions via RTEP process window
    - Stand-alone project
    - Multi-driver – expand scope of existing reliability enhancement
  - Cost-to-benefit ratio ≥ 1.25

Stakeholder Process

RTEP Process Stakeholder Participation

<u>Transmission Expansion Advisory Committee (TEAC)</u>

- ✓ Input on scope and assumptions of RTEP analyses
- ✓ Review & comment on results to date and planned upgrades
- ✓ Provide comments & recommendations to the PJM Board or as requested by Board
- ✓ Upgrade approval authority retained by Board, not TEAC

<u>Sub-Regional RTEP Committees</u>

- ✓ Mid-Atlantic, Western, Southern
- ✓ Review RTEP upgrades at more local level
- ✓ Upgrades at 230 kV and below

Independent State Agencies Committee

- ✓ Advisory body
- ✓ Membership - state regulatory bodies only, voluntary
- ✓ Provide Input and recommendations:
  - Assumptions for evaluating potential transmission needs.
  - Regulatory initiatives.
  - Impact of regulatory actions and other industry trends.
  - Alternative sensitivity studies, modeling assumptions and scenario analyses
- ✓ Public policy driven transmission focus

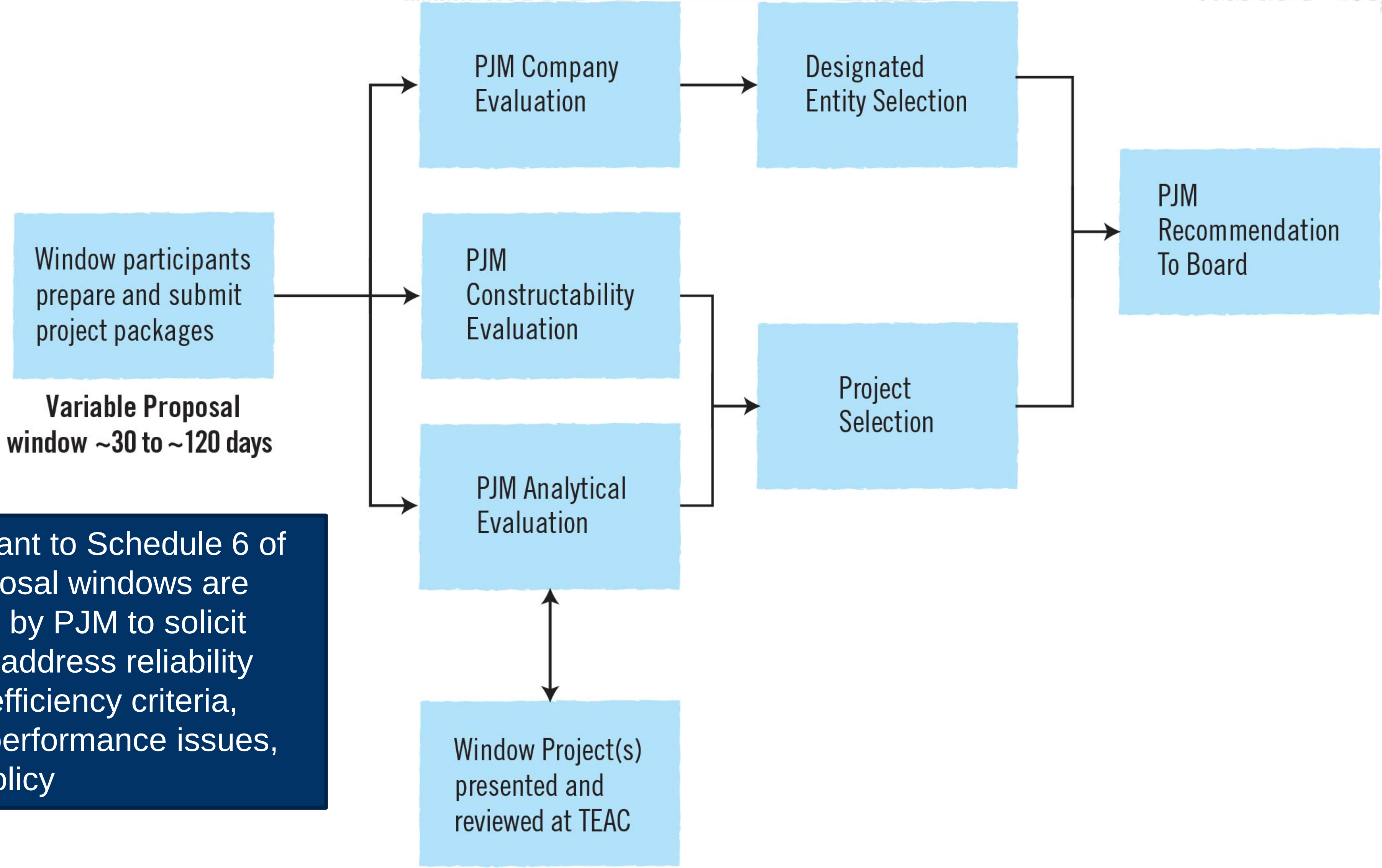
RTEP Process Windows

(FERC Order No. 1000 Implementation)

Window Process for Identifying Solutions

- ✓ Greater opportunities for transmission development by non-incumbents.
- ✓ One or more needs: reliability, market efficiency, operational performance, public policy
- ✓ If included in RTEP, project could be assigned to proposing party to build.
- ✓ Competitive solicitation window based process project classes:
  - *Long-lead projects*: reliability or market efficiency driven system enhancements in year six or beyond – 120 day window
  - *Short-term projects*: reliability driven system enhancements needed in year four or five – 30 day window.
  - *Immediate-need projects*: reliability driven system enhancements needed in three years or less; window if possible, likely less than 30 days nominally.

RTEP Process Window Proposal Evaluation



Note: Pursuant to Schedule 6 of the OA, proposal windows are administered by PJM to solicit proposals to address reliability and market efficiency criteria, operational performance issues, and public policy

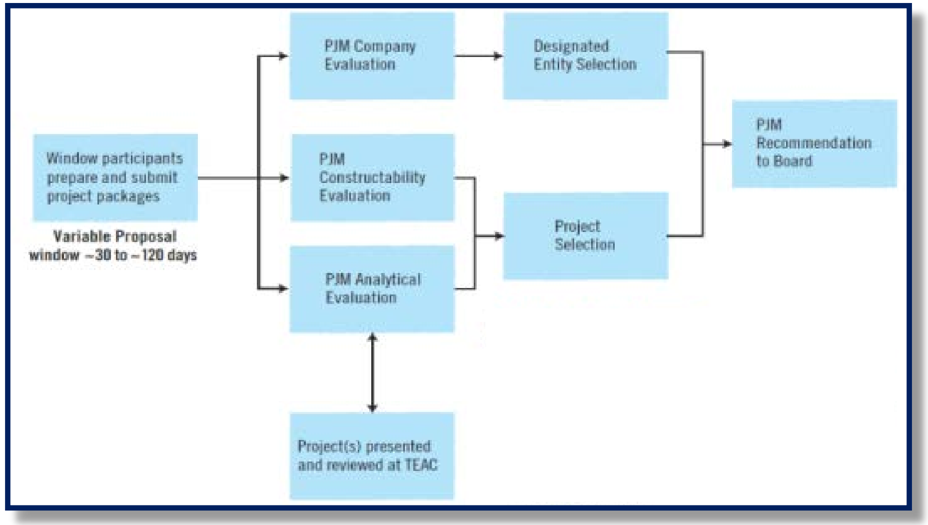
Designated Entity Pre-Qualification

- ✓ For a company to be considered a Designated Entity for proposed project(s)
- ✓ Can this company build and own a *generic transmission project?*
- ✓ Conceptual Criteria:
  - Previous Record, Experience, Plans to Gain Necessary Expertise
  - Standardized Practices
  - Financial Statements
  - Operating Experience: Failures, Remedies, Spares
  - Experience with developing transmission projects

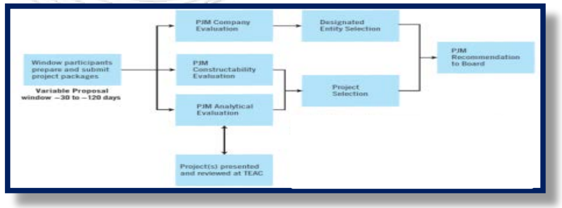
Company Evaluation

- ✓ Info submitted as part of the project proposal package

- ✓ Project specific experience:
  - Evidence of ability to secure financing
  - Engineering / Design
  - Development / Right-of-Way Acquisition
  - Construction
  - Operations
  - Maintenance



Constructability Evaluation



✓ Assessment of project/construction risks:

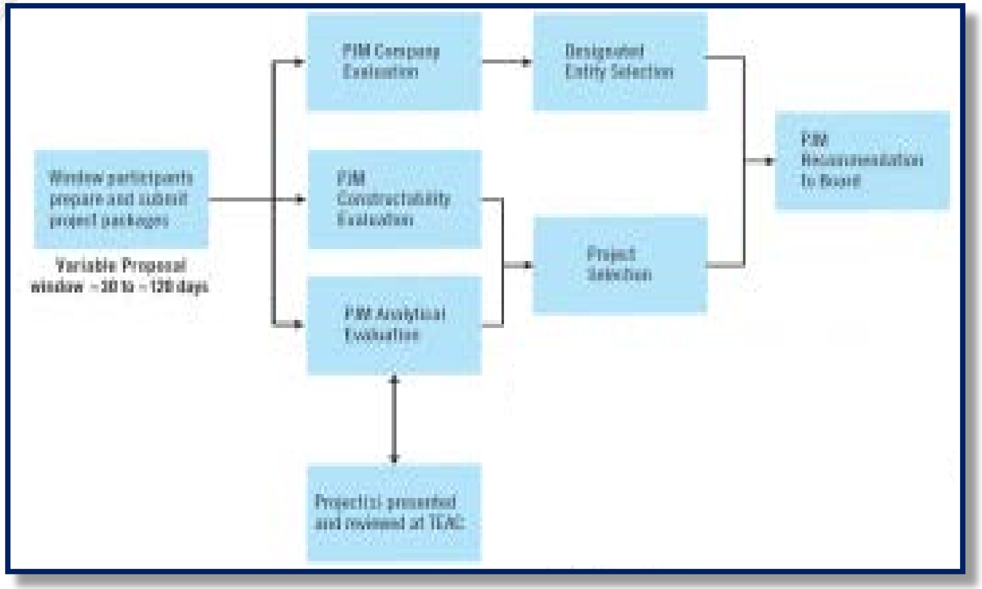
- Cost estimate
  - Design
  - Material
  - Labor
  - Overhead
  - Contingency
- Project finance plan
- Project plan
  - Permits required
  - Right of way acquisition
  - Project one-line diagram
  - Station(s) general arrangement
  - Transmission line route
- Operational plan
  - Control center
  - Telemetry

- Schedule
  - Engineering
  - Right of way acquisition
  - Long lead time equipment
  - CPCN requirements
  - Construction permitting
  - Construction activities
  - Contract labor procurement plan
  - Outage plan
- Maintenance plan
- Compliance with standards organizations
- Other data as required

Analytical Evaluation

Reliability Analyses

- ✓ Does project solve issue as proposed?
- ✓ Does it cause other reliability issues?
- ✓ Similar analyses for operational performance issues



Market Efficiency Analyses

- ✓ Congestion relief as proposed?
- ✓ Meet established 1.25:1 benefit-to-cost metric?

Public Policy Analyses

- ✓ Ability to satisfy public policy objectives

Board Oversight

Board Oversight

- PJM develops recommended solutions to the identified needs and reviews the results with stakeholders at the TEAC and/or Subregional RTEP Committee meetings

- PJM invites interested parties to comment on recommended solutions before submitting the recommended plan to the PJM Board of Managers

- PJM staff typically reviews overall status of the RTEP at several times during the year

- PJM Board approves the recommended plan in accordance with Schedule 6 of the Operating Agreement
  - Approves the cost allocation for the approved projects consistent with Schedule 12 of the OATT

Post Approval Process

Post Approval Process - Notifications

- Within 10 days of approval by the Board, PJM notifies entities that have been designated to build an approved RTEP project

- Within 30 days of being notified of responsibility to build a new greenfield project, the TO or non-incumbent transmission developer shall notify PJM of their acceptance of designation and submit a development schedule.

- Within 90 days of being notified of responsibility to build an upgrade to an existing facility the TO must notify PJM that they accept the designation and provide a proposed preliminary schedule.

Post Approval Process - Notifications

- Within 15 days “or other reasonable time” PJM must notify the developer of any issues with the development schedule and tender a Designated Entity Agreement (DEA)

- Within 60 days of receiving the DEA, the Designated Entity must return and executed DEA and submit a letter of credit for an amount of 3% of the project cost, to cover the incremental cost of construction that could result from reassignment of the project.

- Within 30 days of approval, PJM shall file a report with FERC that identifies:
  - the expansion or enhancement
  - its estimated cost
  - the entity or entities that will be responsible for building the enhancement
  - the market participants that will bear the cost of the project

- Following Board approval the final RTEP shall be documented, posted publically and provided to applicable Regional Entities

- PJM Construction Status Page: http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

- PJM Cost Allocation Page: http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx

Project Tracking

- Obligation to Build – Transmission owners or Designated Entities designated to construct a facility are obligated to do so under the Operating Agreement (Schedule 6 of the OA section 1.7)
  - Per OA schedule 6 section 1.7(d) a transmission owner may decline to construct an economic project.
  - PJM is required to file a report at FERC in those instances

- Entities designated to construct a transmission enhancement are expected to regularly provide PJM with project updates (including cost and schedule)

- Project status is updated on the PJM website

New Service Requests

- Generation Interconnection
- Merchant Transmission Interconnection
- Long-term Firm Transmission Service
- Auction Revenue Rights

Network Projects

- Once PJM completes the “baseline” RTEP process as described on the previous slides, the clean baseline case is then used to study new service customer requests

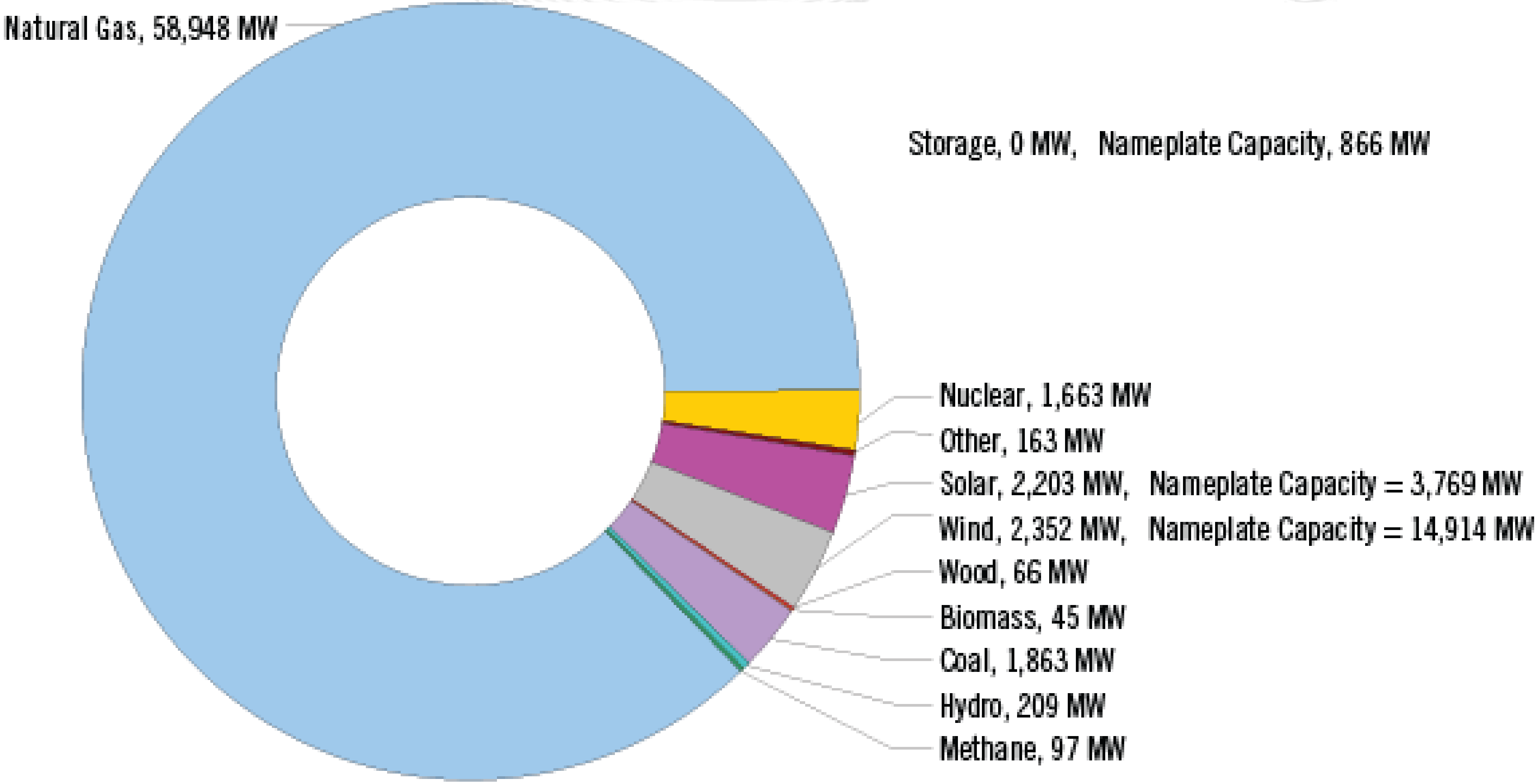
- Upgrades required pursuant to PJM’s new service request process are referred to as “network” upgrades

Queue Process

New Service Requests (queue open) → Studies (Feas | Imp | Fac) → ISA/CSA/UCSA/ WMPA Execution → ISA/CSA/UCSA Implementation → Commercial Operation

- ✓ Governed by PJM Open Access Transmission Tariff (OATT)
- ✓ Projects may drop out of the queue at any time
- ✓ Project size may be reduced but not increased

PJM Queued Generation Fuel Mix – Requested Capacity Rights (December 31, 2015)



Generation Project Progression – Capacity Rights, MW

Following ISA/WMPA execution, **10,201 MW of capacity** with ISAs and **411 MW of capacity** with WMPAs withdrew from PJM's Interconnection process. Another **25,512 MW** have executed agreements but were not in service as of December 31, 2015. Overall, **10 percent of requested capacity** megawatt reaches commercial operation.

Posted Queue Information

- Generation Interconnection
- Merchant Transmission
- Long-Term Firm TSR Customers
- Generation Deactivation
- ARR Analyses
- RTEP Upgrades & Status
- RTEP Development
- Resource Adequacy Planning
- Planning Criteria
- Design, Engineering & Construction
- Interregional Planning

Generation Queues: Active (ISA, WMPA, etc.)

Generators at transmission level voltages that request interconnection with PJM, and want to participate in PJM's wholesale power markets, must execute an **Interconnection Service Agreement**. Generators at local distribution or sub-transmission voltage levels may also request to participate in PJM's wholesale power market. However, they may not be under Federal Energy Regulatory Commission jurisdiction regarding the nature of their interconnection request. If not jurisdictional, each such generator must sign a Wholesale Market Participation Agreement instead of an Interconnection Service Agreement upon completion of all required reliability studies. A **Wholesale Market Participation Agreement** defines the terms and conditions under which PJM wholesale power market participation will be conducted. It also contains a milestone for the generator to execute, separately, an interconnection agreement with the local electric distribution company in accordance with the respective state's own established process.

A system map is available showing the location of each active and withdrawn interconnection request.

Legend

XML

Fuel Type: All Status: All State: All Search Reset

Showing 1 - 13 of 13 Page 1/1 View : 50

A B C D E F G H I J K L M N O P Q R S T U1 U2 U3 U4 V1 V2 V3 V4 W1
W2 W3 W4 X1 X2 X3 X4 Y1 Y2 Y3 Z1 Z2 AA1 AA2 AB1 All

Queue	AQ	Queue Date	PJM Substation	MW	MW In Srvc	MWC	MWE	Stat	Feas	Imp	Fac	ISA/ WMPA	CSA	St	Projected In Service	Fuel
U4-001		11/03/2008	Howard 138kV	200		26	200							OH	2018 Q4	
U4-008		11/13/2008	South Central Power	6.4	5.6	6.4	6.4					W		OH	2011 Q1	
U4-009		11/17/2008	Louisa 230kV	144	3	3	3							VA	2009 Q2	
U4-014		11/24/2008	Siegfried-Hauto 69kV	10	10	3.8	10							PA	2012 Q4	
U4-015		11/25/2008	Rock Springs 500kV	475	8.7	8.7	8.7							MD	2009 Q2	
U4-027		12/22/2008	Normandy-Kewanee 138kV	100		100	100							IL	2016 Q4	

Supplemental Project

1.42A.02 Supplemental Project.

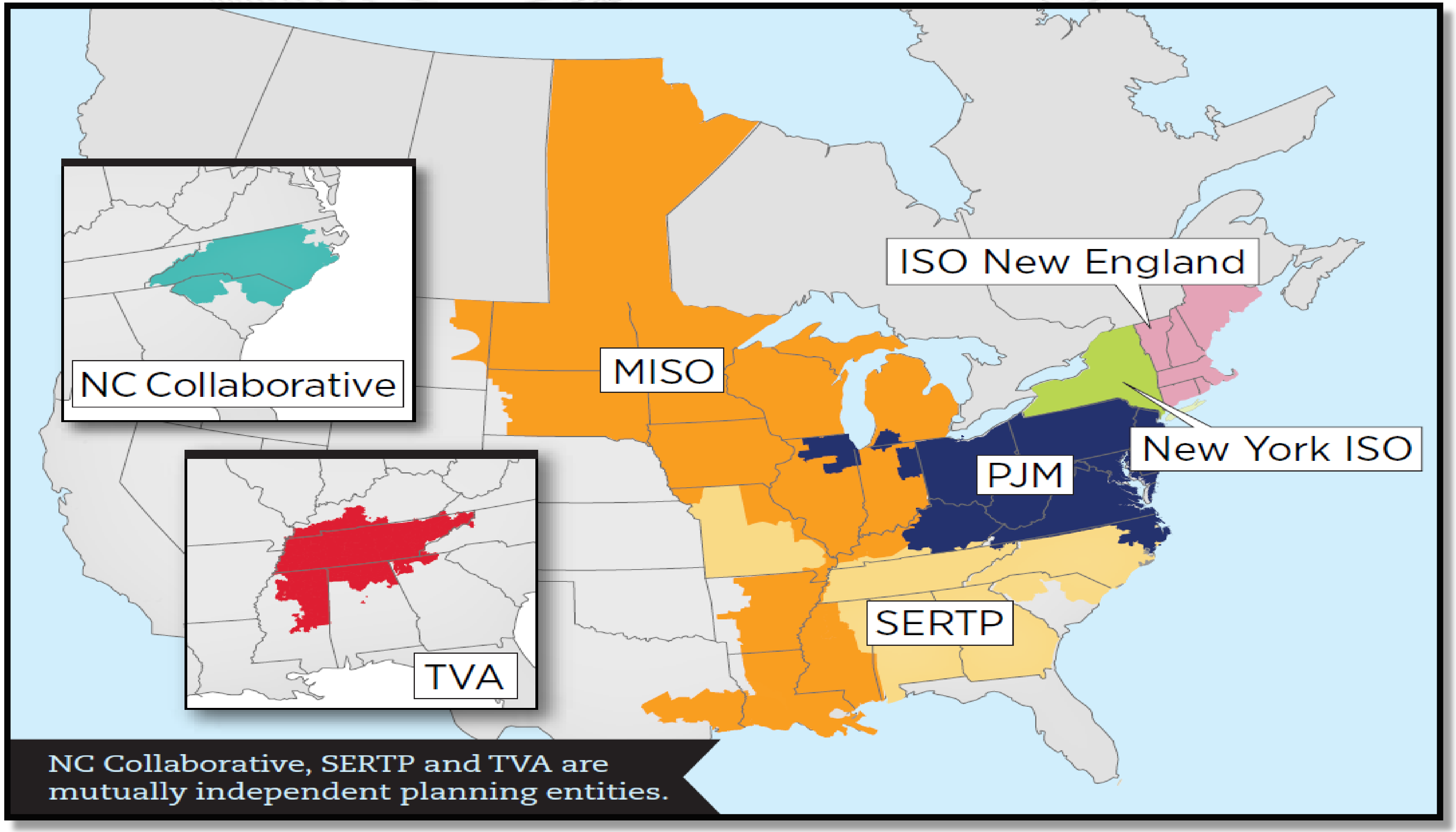
"Supplemental Project" shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to section 1.5.9(a)(ii) of Schedule 6 of this Agreement. Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

- PJM studies Supplemental Projects to identify any adverse reliability impacts of the project
  - Reliability impacts must be addressed as part of the scope of the supplemental project
- Incorporated into RTEP models
- Not approved by the PJM Board
- Not cost allocated under Schedule 12
- Reviewed with stakeholders at TEAC and/or Subregional RTEP Committee meetings

Interregional Coordination

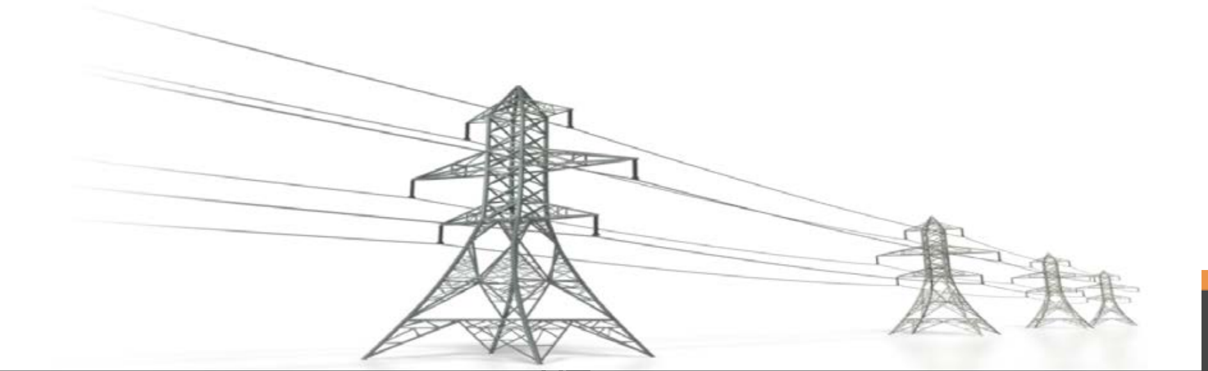
RTEP Process - Interregional Coordination

- ✓Interregional electricity markets
- ✓System interoperability
- ✓Interregional coordination agreements



Interregional Coordination Studies

- ✓ Order 1000 Interregional planning requirements
- ✓ Seams reliability and congestion issues
- ✓ Interregional impacts of queued interconnection requests
- ✓ Cross-border impacts of regional transmission plans
- ✓ Stakeholder raised issues best addressed through joint coordination
- ✓ National and state public policy objectives; e.g., RPS



End-of-Life Linkages to RTEP

- At some point everything will reach it’s end-of-life (EOL)
- To the extent a TO has specific EOL criteria in their FERC form 715 criteria, projects required to address EOL issues are incorporated into the RTEP as a “baseline” project
- For transmission owners that do not include specific EOL criteria in their FERC form 715 criteria. EOL equipment issues are addressed with Supplemental projects