



ATSI Integration Stakeholder Meeting

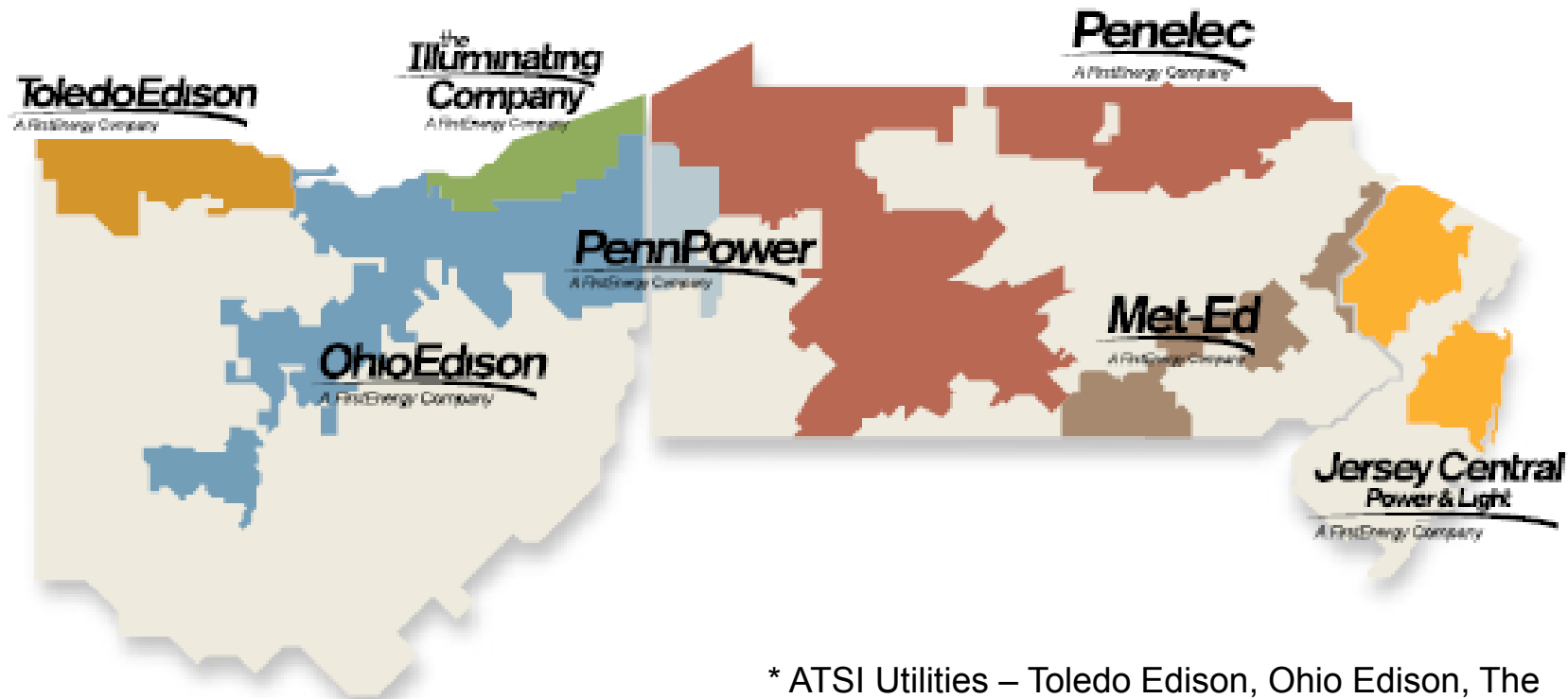
Cleveland, OH
10/19/2009

- Introductions and Welcome
- ATSI Integration Overview
- Operations Integration
- Markets Integration
- Generator Interconnection Process
- RPM Transition
- Capacity Testing
- Compliance
- Stakeholder Training
- Participant Readiness
- Other Questions and Concerns



ATSI Integration Overview

ATSI Utilities* to integrate into PJM operations on June 1, 2011

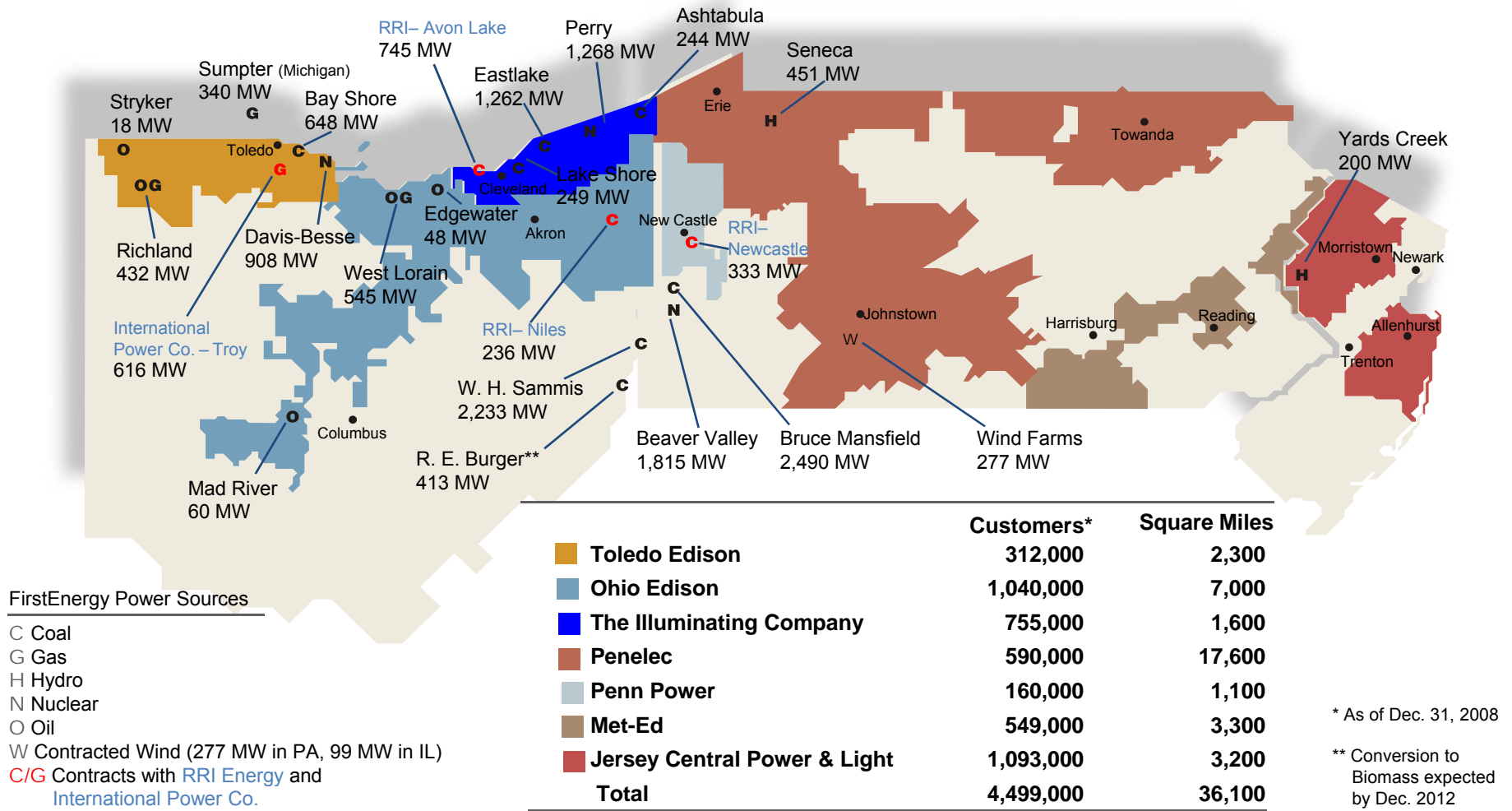


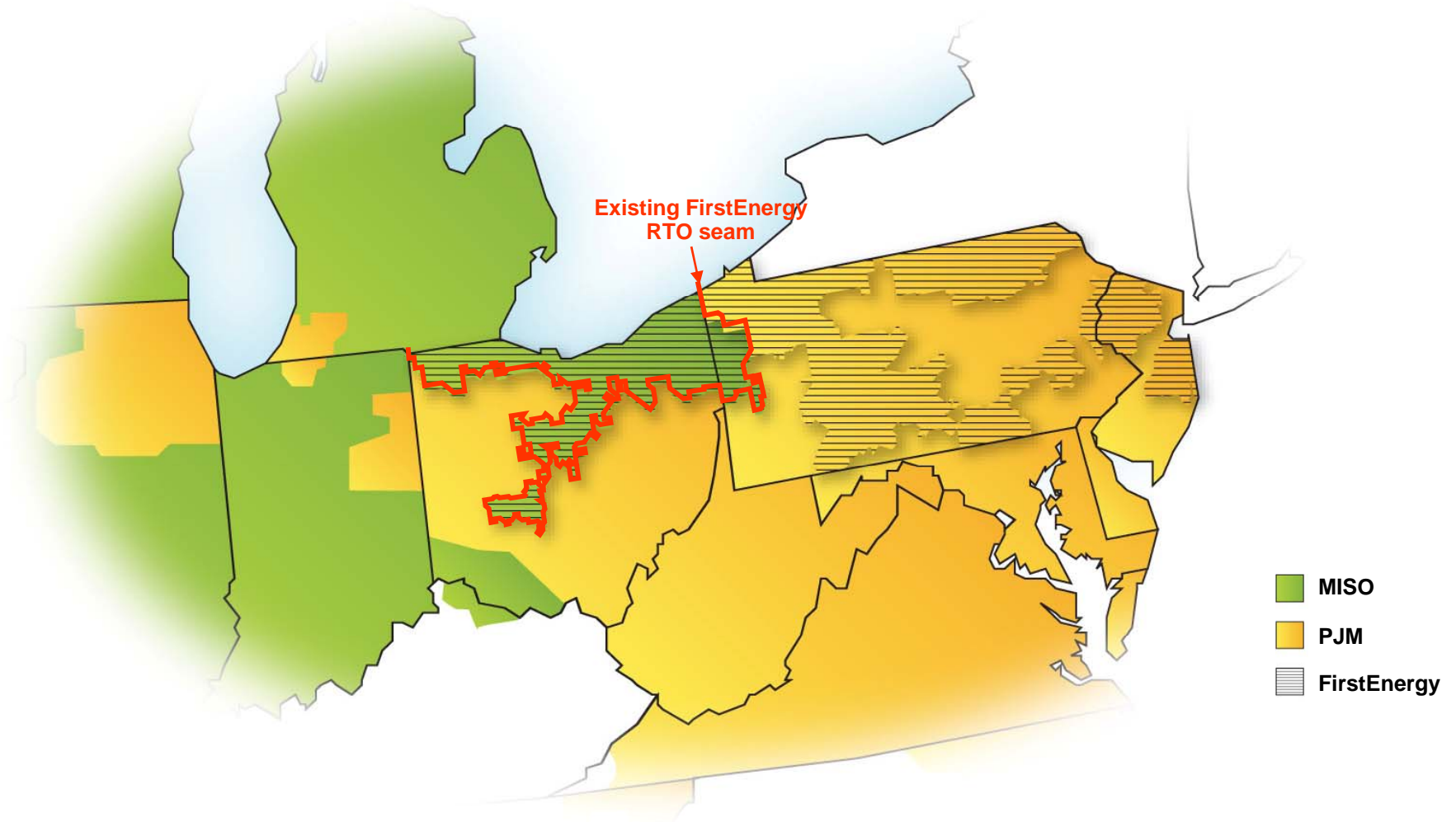
* ATSI Utilities – Toledo Edison, Ohio Edison, The Illuminating Company, and PennPower

FirstEnergy Corporate Profile

- **Diversified energy company headquartered in Akron, Ohio**
- **Involved in generation, transmission and distribution of electricity, as well as other energy-related services**
- **Fifth largest investor-owned electric system in U.S.**
 - 4.5 million customers in Ohio, Pennsylvania and New Jersey
 - Diversified customer base
- **Controls more than 14,300 MW of generating capacity**
 - 39% nuclear; 61% fossil/other (2008 output MWh)
- **Approx. \$14B in annual revenues and more than \$33B in assets**
- **Approx. \$12B market capitalization**
- **Investment grade credit ratings**

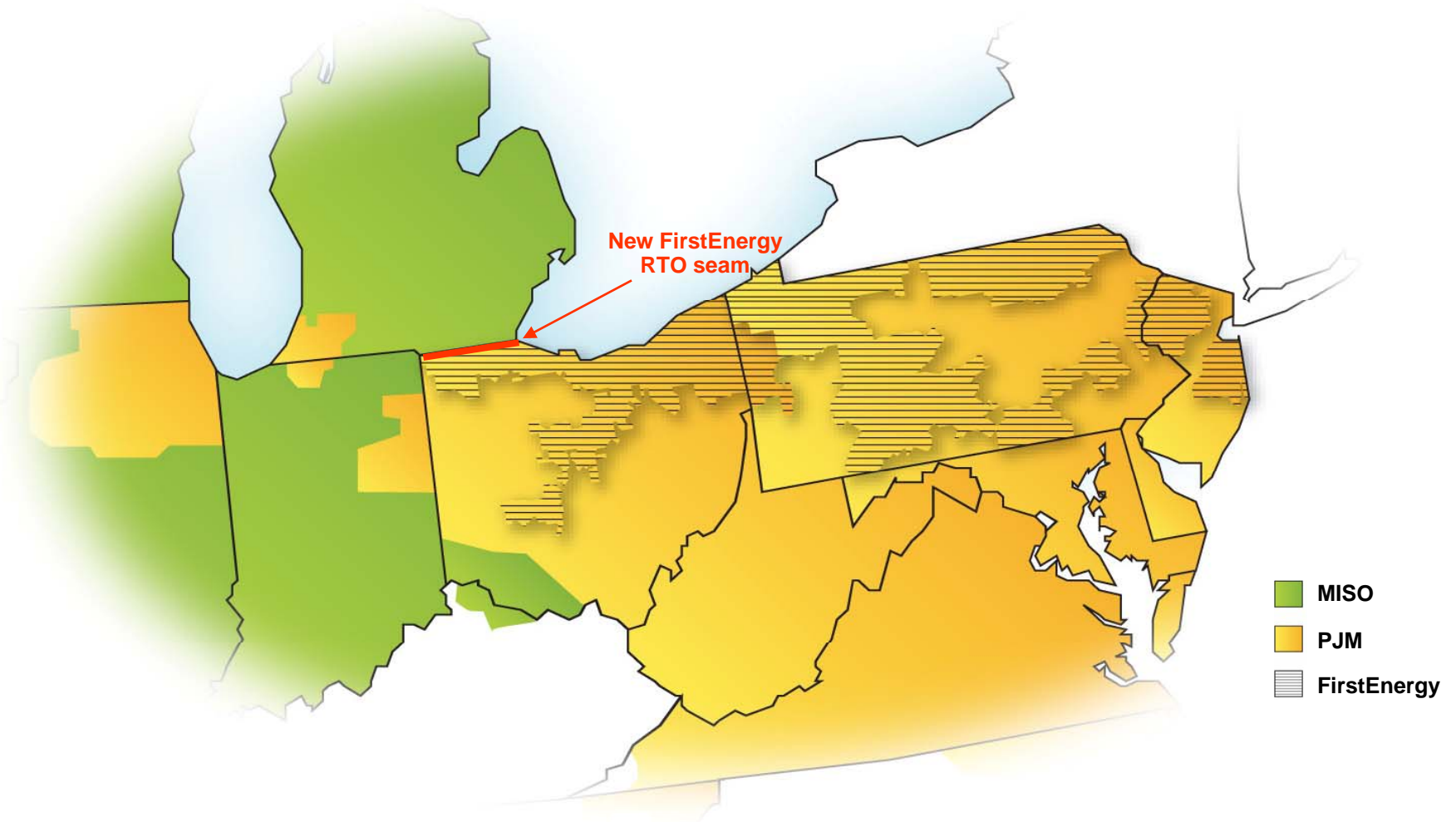








ATSI Transmission System – Post-integration



October 2009 – IRM Study and
Generator deliverability tests completed

A large, light blue downward-pointing arrow with a subtle grid pattern, indicating the flow from the first event to the second.

January 2010 - Load deliverability
tests completed

A large, light blue downward-pointing arrow with a subtle grid pattern, indicating the flow from the second event to the third.

May 2010 RPM Base Residual
Auction - CETO/CETLs for the ATSI
Load Deliverability Area provided

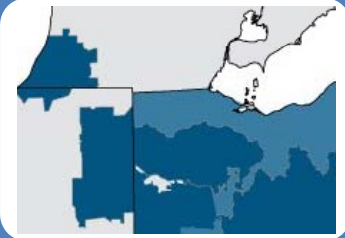
December 2009 – FERC approval of FRR auction plan

A large, light blue downward-pointing arrow with a subtle grid pattern, indicating the flow from the first event to the second.

March 2010 – FRR auctions for 2011-2012 and 2012-2013 delivery years completed

A large, light blue downward-pointing arrow with a subtle grid pattern, indicating the flow from the second event to the third.

May 2010 – RPM Base Residual Auction for 2013-2014 delivery year completed.



PJM EMS Model to be expanded to include all of the ATSI Utilities and more of MISO in Michigan



All transmission and generator outages submitted into eDART to support the outage planning process



All transmission operators and generator operators to become PJM-certified



Legal/Regulatory – Highlights

August 14, 2009

August 17, 2009

December 2009

Later

ATSI and PJM
have executed
an integration
agreement

ATSI
submitted
filing to
FERC

ATSI
requested
FERC
filing
approval

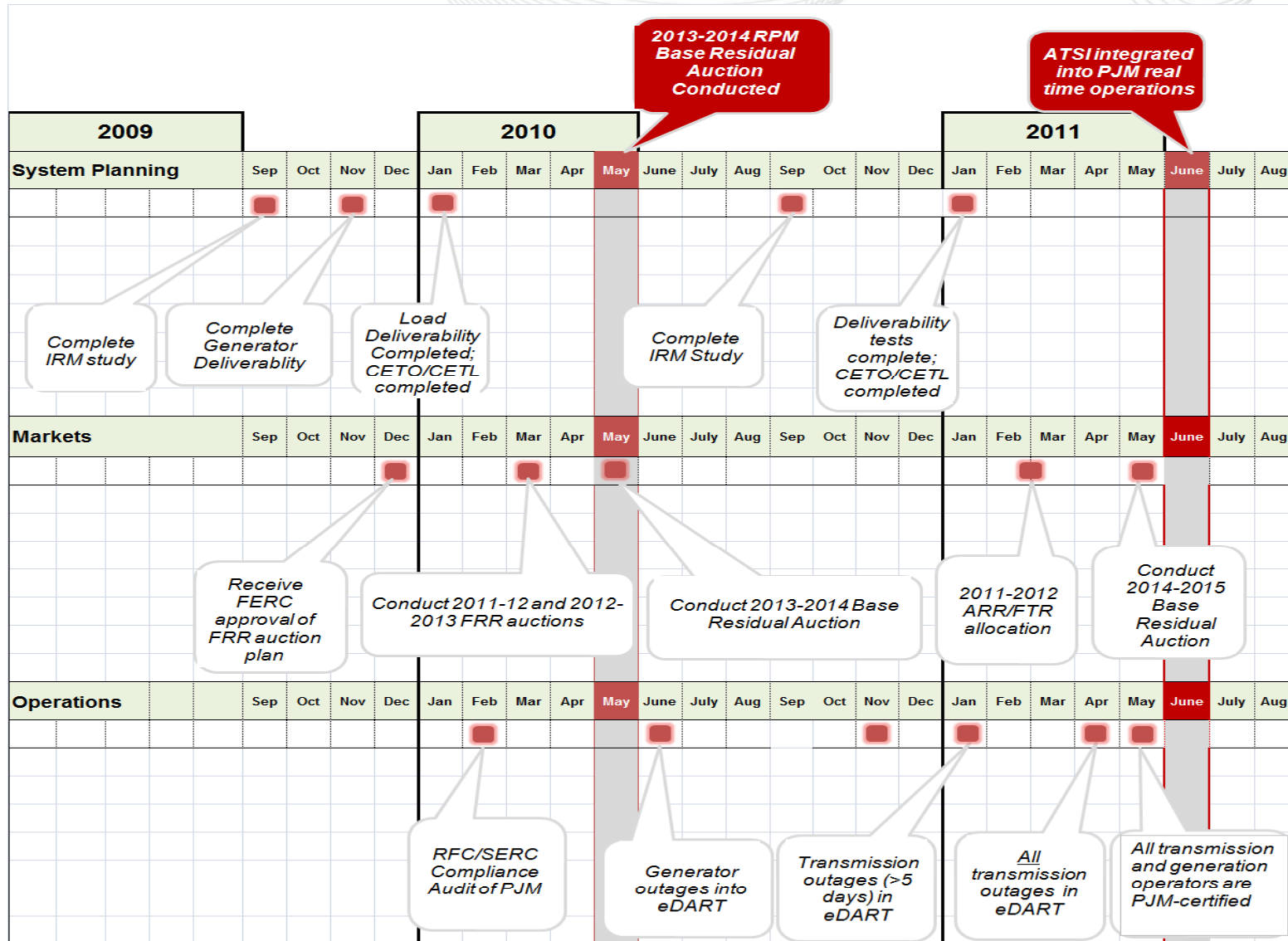
Additional
FERC filings
in support of
ATSI
integration

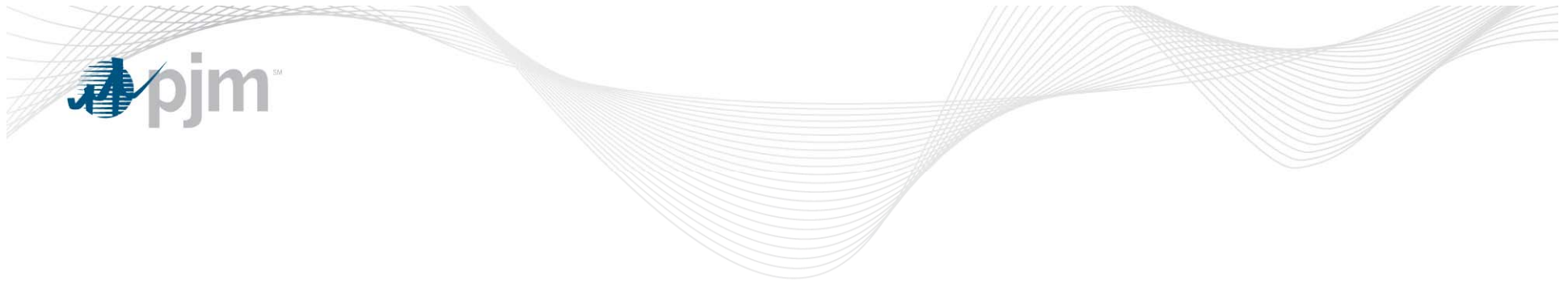


Estimated Integration Costs

	Est. Expense	Est. Capital
Operations	\$1,100,000	\$1,200,000
Markets	\$700,000	\$450,000
Planning	\$100,000	\$600,000
IT Infrastructure	\$400,000	\$500,000
Compliance/Trans. Service Conversion	\$400,000	\$250,000
Miscellaneous	\$500,000	
Project Management	\$1,500,000	
Training	\$300,000	
TOTAL	\$5,000,000	\$3,000,000

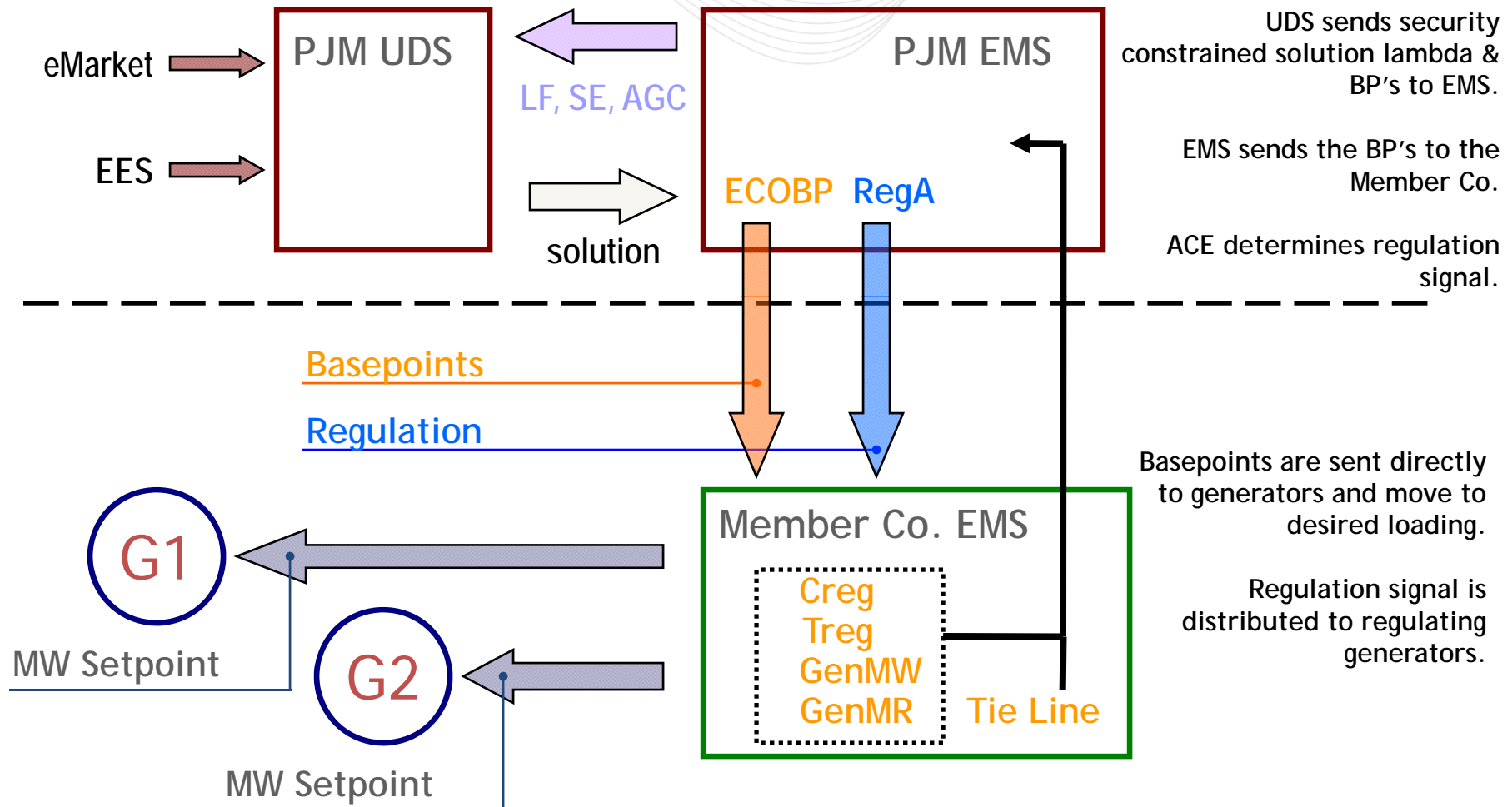
Integration Milestone Schedule





Operations Integration

PJM Signal Path Diagram



Points sent to PJM

- All Generators
 - Low side Generator MW (GENMW)
 - Low side Generator MR (GENMR)
- Additional for Wind Farms
 - Weather Data per Wind farm
 - Temperature (F)
 - Wind speed
 - Wind Direction
 - Barometric pressure
 - Humidity

Refer to PJM Manual 1 section 5 for more information

Points sent from PJM

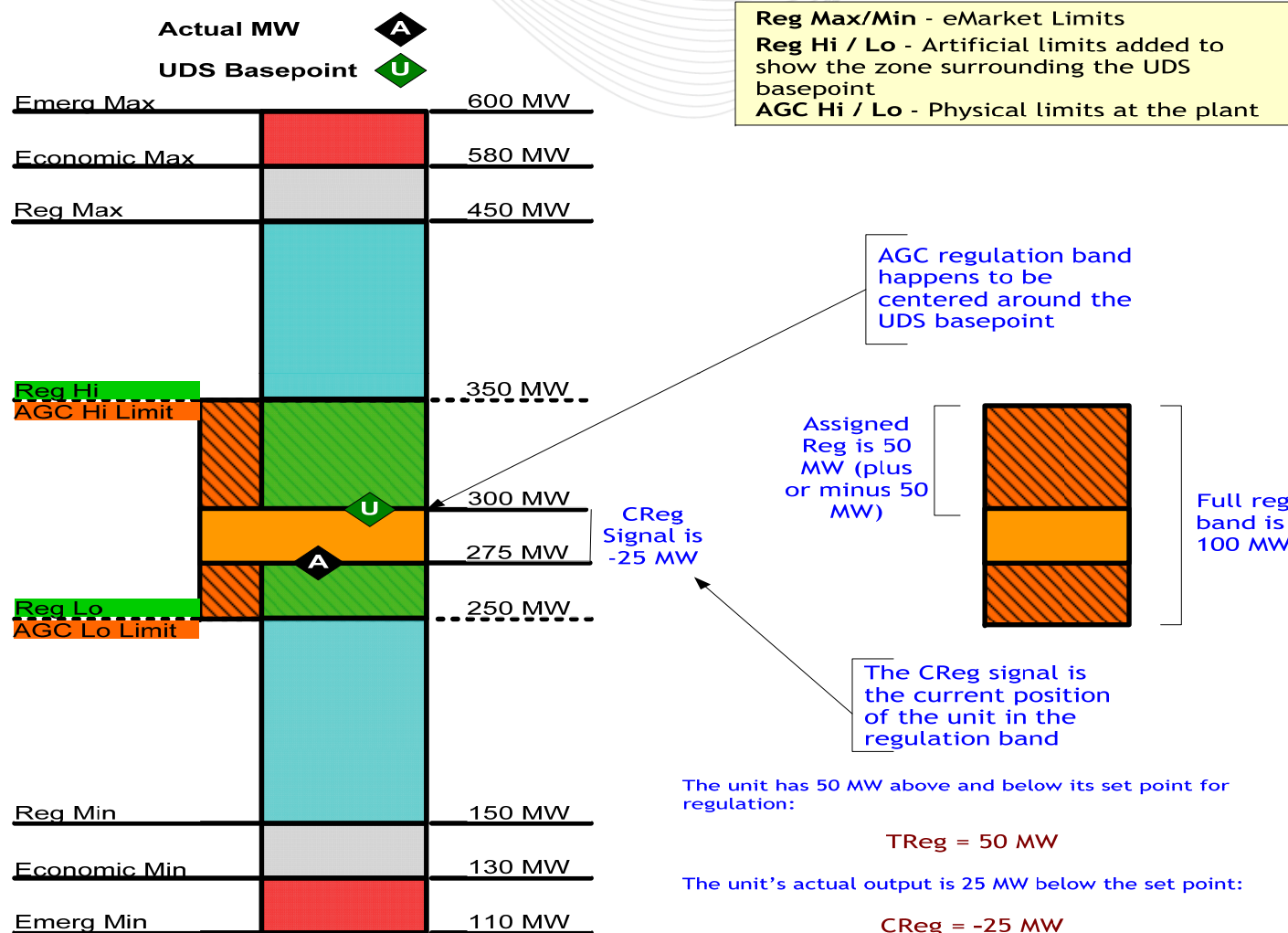
- UDS control point for each Generator Unit
 - Economic Base Point (ECOBP)
 - Economic Max (ECOMX)
 - Economic Minimum (ECOMN)
 - Unit Dispatch Reason (GENRUNR)
 - Cost
 - Assigned Regulation (AREG) - if in regulation Market
- For Wind Farms
 - Economic Base Point (ECOBP) – To cap output

Refer to PJM Manual 1 section 5 for more information

- *Fleet-wide* signal sent *from* the Generation Marketer for each control area.
 - Total Regulation (TReg):
 - A calculated value (positive) of the amount of regulation (MW) that is on control.
 - Current Regulation (CReg):
 - A calculated value (positive/negative) of where the fleet is operating relative to its regulation band.
- *Fleet-wide* signal sent *from* PJM for each control area.
 - Regulation assigned (RegA):
 - Regulation control signal (positive/negative).

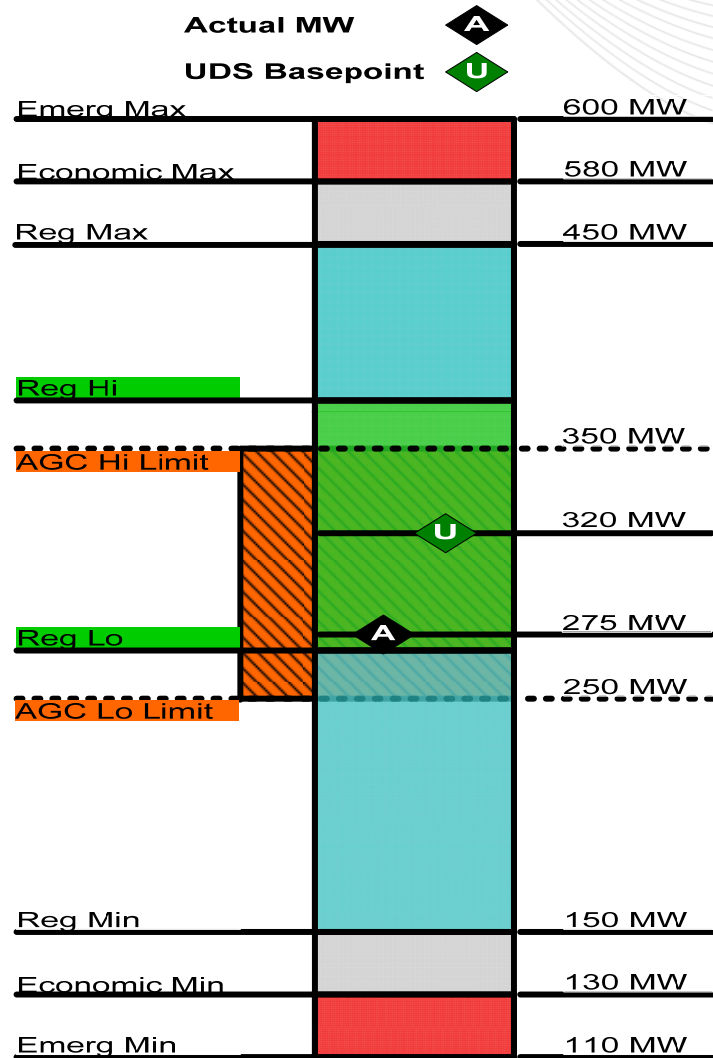
Refer to PJM Manual 12 section 4 for more information

Regulating generator – PJM format



Note: TReg is always positive. CReg is always bounded by TReg. (i.e. $-TReg < CReg < +TReg$)

pjm Plant limits restrict regulation capability



As the UDS basepoint moves, a decision must be made about which AGC band will be used.

The CReg signal is the current position of the unit in the regulation band

If a UDS basepoint philosophy is used, TReg is reduced by the AGC Hi Limit & CReg is based off the midpoint of this limited regulation band:

$$TReg = (350 - 270) / 2 = 40 \text{ MW}$$

$$CReg = (275 - 310) = -35 \text{ MW}$$

This unit could be considered as having a higher priority to following the UDS basepoint.

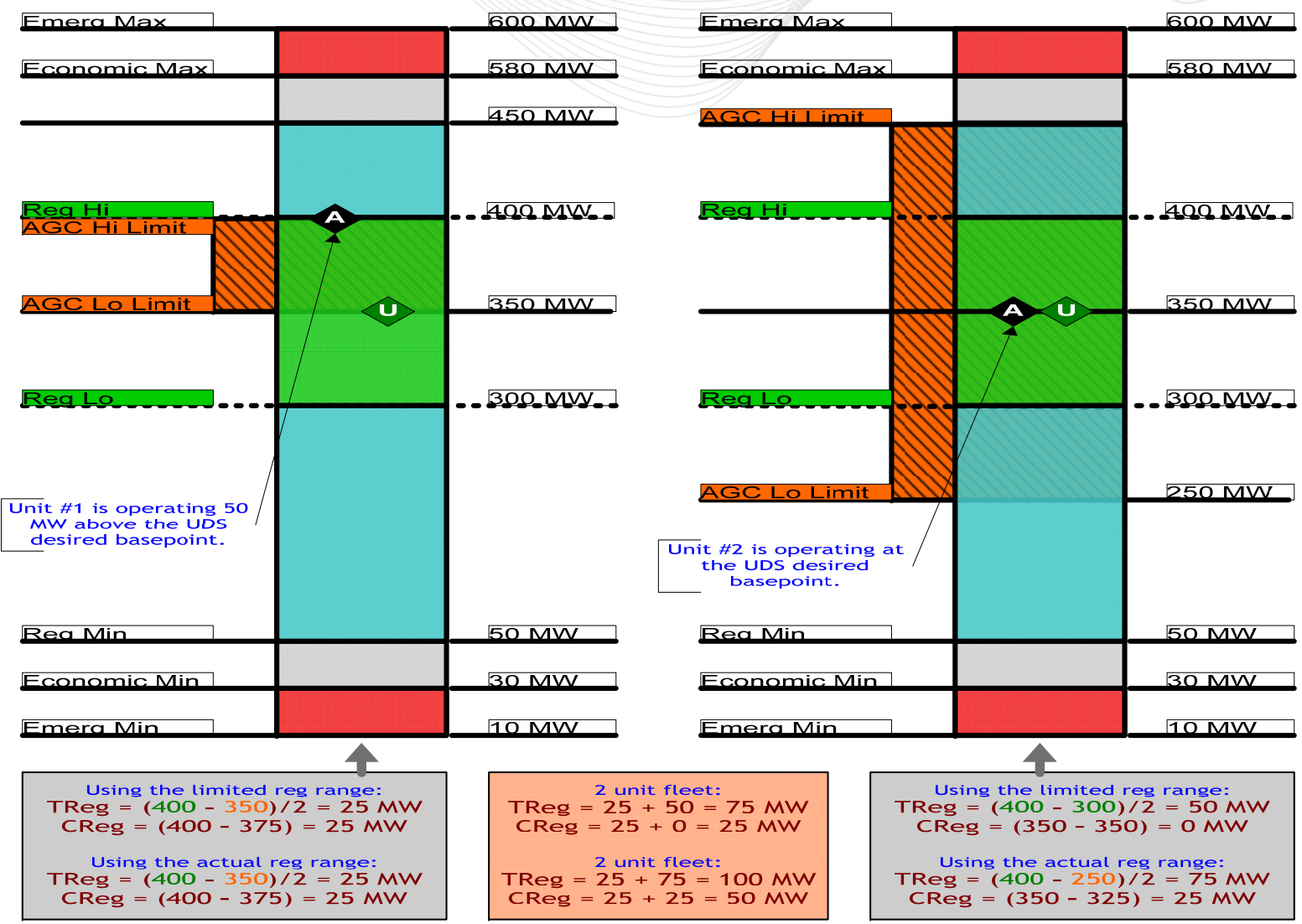
If a regulation band philosophy is used, TReg is based on the orange band & CReg is based off the midpoint of this regulation band:

$$TReg = (350 - 250) / 2 = 50 \text{ MW}$$

$$CReg = (275 - 300) = -25 \text{ MW}$$

This unit could be considered as having a lower priority to following the UDS basepoint and more to its regulating capability.

Fleet regulation sharing





Company Regulation Responsibilities

- Important regulation characteristics
 - Bid in response rate is achievable (5 min.).
 - Turn around time is minimal.
 - Full raise/full lower can be achieved.
 - TReg is maintained as close as possible to the Market assigned regulation.

Refer to PJM Manual 12 for more information



Pseudo Ties/Dynamic Schedules

- Used to move Generation in and out of PJM
 - These will be evaluated on an individual bases with as special case documents.

Forecast Planned Outages

- Generation owners submit MW outages of greater than 31 days in the future, and up to 3 years in the future as “Forecasted Planned.”
 - Peak Period Maintenance (PPM) is defined as the 24th through the 36th Wednesdays of the calendar year with each week beginning on a Monday. Usually from about June 16th through September 8th
- Each evening the eDART system will automatically change to “Planned” all “Forecasted Planned” outage due to start in less than 31 days.
- Once ticket is changed to “Planned,” and has a status of approved, a reduction revision can be submitted, but only to decrease the amount of reduction.
- Start date can be increased only (no more than 30 days into the future)
- End date may be changed
- Other than cancellation, no other changes can be made.

Refer to PJM Manual 10 section 2 for more information

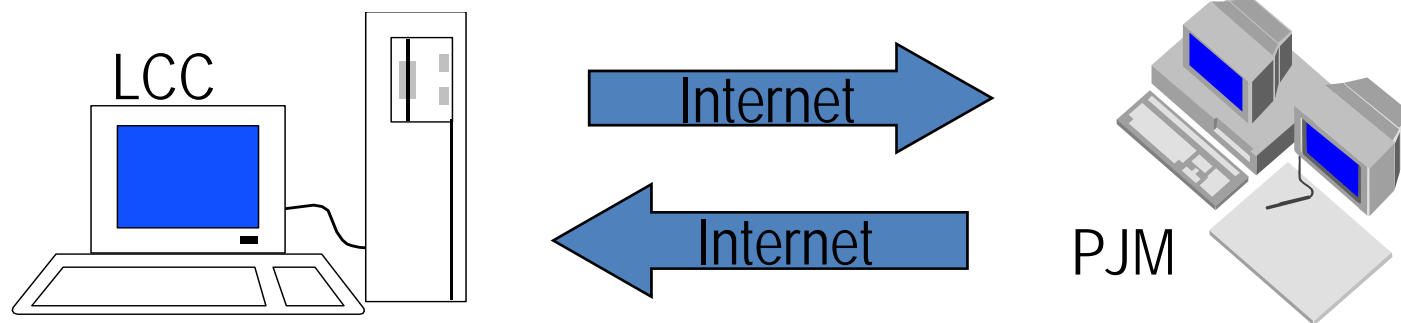
- Outages that may be **deferred** beyond the next weekend (**Next Monday Morning, 0800hrs**)
- Work has to be done before next planned outage
- Flexible dates
- Much shorter than planned outages
- Predetermined duration
- Timeline
 - Weekend Period - Friday at 2200 to Monday at 0800
- Limitations
 - Peak Period - 9 days
 - Non-Peak Period - Unlimited

Refer to PJM Manual 10 section 2 for more information

- Responsibilities upon an Unplanned Outage:
 - **Notify PJM Generation Operator**
 - Update Unit Limits/Status in eMKT
 - Unit Hourly Update screen
 - More later!
 - Submit eDART ticket in timely manner
 - When unit status is known
 - Submit eGADS data
 - By 20th day of following month

Refer to PJM Manual 10 section 2 for more information

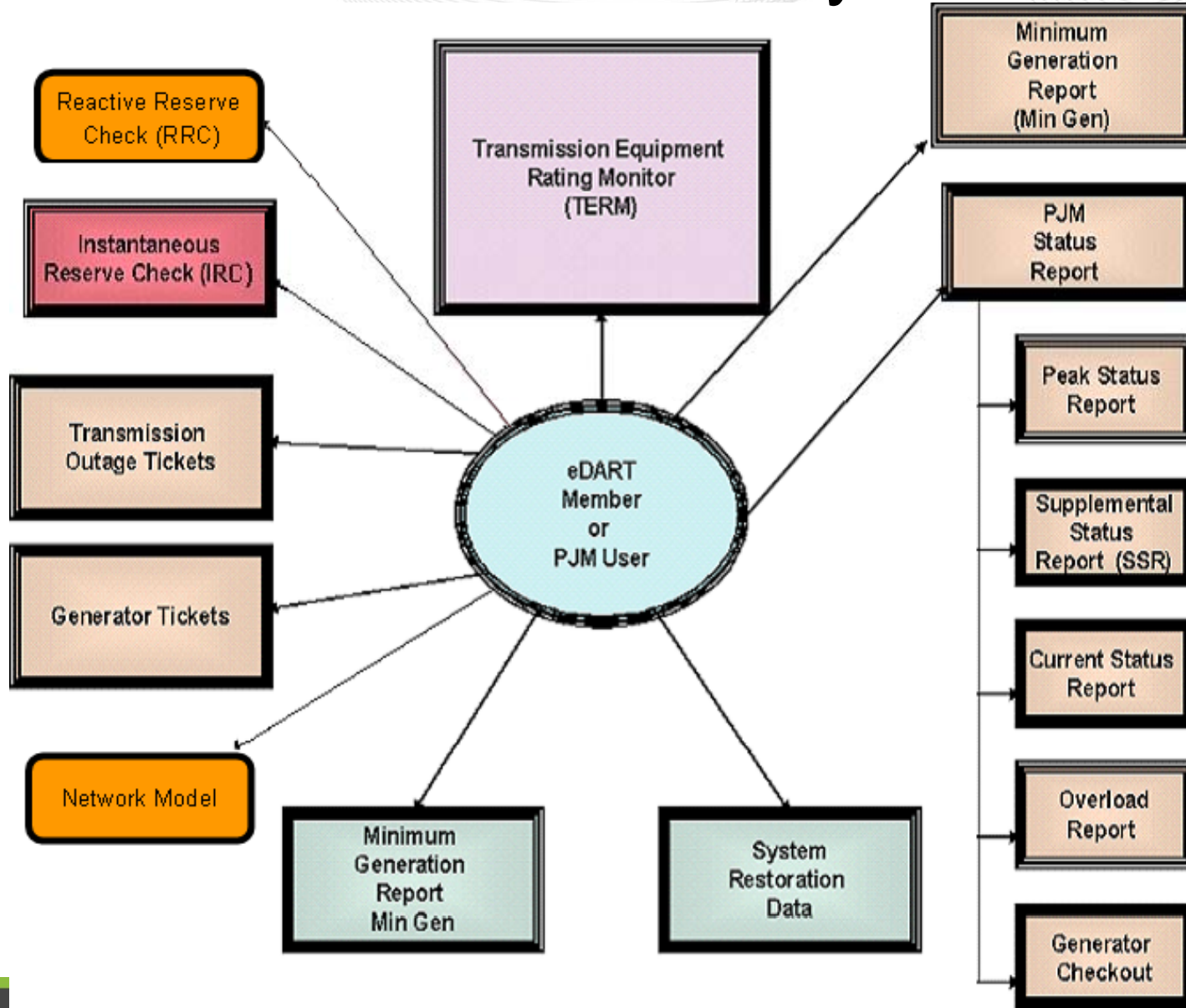
- eDART stands for Dispatcher Applications and Reporting Tool
- eDART is an internet tool for submitting Generation and Transmission operations and planning data to PJM and retrieving operations data from PJM



Refer to:

http://www.pjm.com/markets-and-operations/etools/edart/edart-training-presentations.aspx?sc_lang=en

eDART System Overview





eDart Generation Reporting

- Generation Owners required to report through eDART
 - MW Outages (just described)
 - Unit MVAR Capability changes
 - Voltage Regulator Outages
 - Unit Governor Outages
 - MVAR Testing Ticket
 - D-Curve Reports
- Instantaneous Reserve Check
- Minimum Generation Report
- PJM Status Report
 - Supplemental Status Report
 - Gen Checkout
- E-Mail Notification Feature



Generation Performance Monitor

- GUI, PI Process Book and OSI Web Parts
 - Information to display
 - Scheduled Voltage
 - High / Low limit
 - Current Voltage
 - 30 Minute Average of Voltage
 - Unit Status – On / Off Line–Mvar limits exceeded, Lead / Lag–Warning / Violation indications–Mvar Trend with limits–MW reserves Trend with reserve values
- MW performance display tracks generator performance:
 - As compared to PJM Unit Dispatch System (UDS) set point.
 - Provides view into eMkt unit bid data used in UDS solution.
 - Provides unit reserve information.
- Providing visualization into eMkt data/ real-time reserve calculations will provide a feedback tool for MOC to take action to update eMkt data in real-time.

Refer to: <http://www.pjm.com/~media/committees-groups/committees/oc/20071218-item-08-generation-performance-monitoring-program.ashx>

	TOTAL CAPACITY	CONNECTING ASSET	COM DEVICE	PROTOCOL	NETWORK
Path A	> 500 MW	 Control Center Gen	SCADA System	ICCP	PJMnet (dual router)
Path B		 Gen			
Path C	100-500 MW	 Control Center Gen	SCADA System	ICCP	PJMnet (single router)
Path D		 Gen			
Path E	0-100 MW	 Gen	 Director	DNP3 Encrypted	Internet

- Transmission Owners must have satellite phones at both their primary and back-up facilities

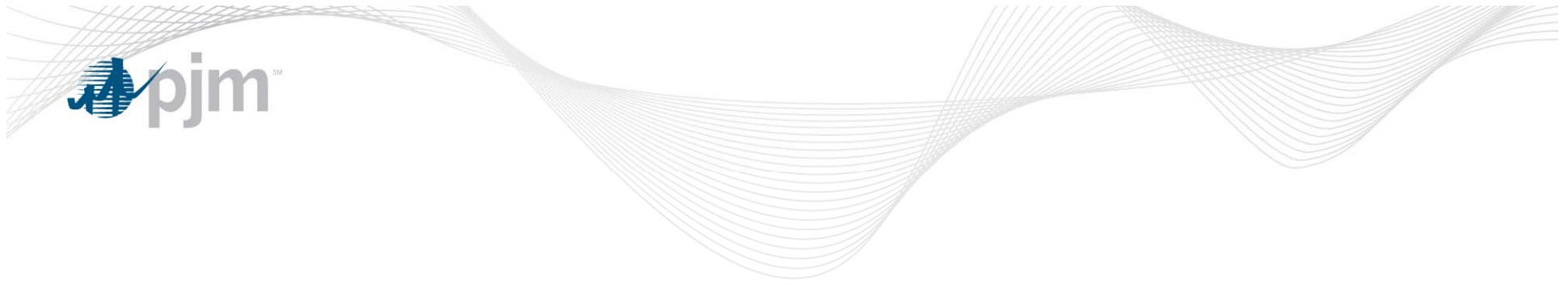
- Generation Operator (GO) Control Centers must have satellite phones when one or more units total 500 MW or greater





Contact Information

Task	Contact Person	Email	Phone	Client Manager
Outage Scheduling	Ed Hoey	hoeyep@pjm.com	610-666-8844	
AGC, Data	Jeff Hoffman	hoffmj@pjm.com	610-666-2264	
Wind, Reactive	Sanjay Patil	patils@pjm.com	610-666-4295	



Markets

- Markets

- Day-Ahead Market (Forward)
- Unit Dispatch
- Locational Marginal Pricing
- Ancillary Services

(Real-Time)

- Automatic Generation Control (AGC)
 - ACE & Frequency Bias.
 - NERC Control Performance Standard (CPS/BAAL).
- Regulation
 - AGC & Regulation breakdown.
 - Enhanced regulation concepts: TReg, CReg, & AReg.
 - TReg/CReg examples.
 - TReg/CReg real-time plots.

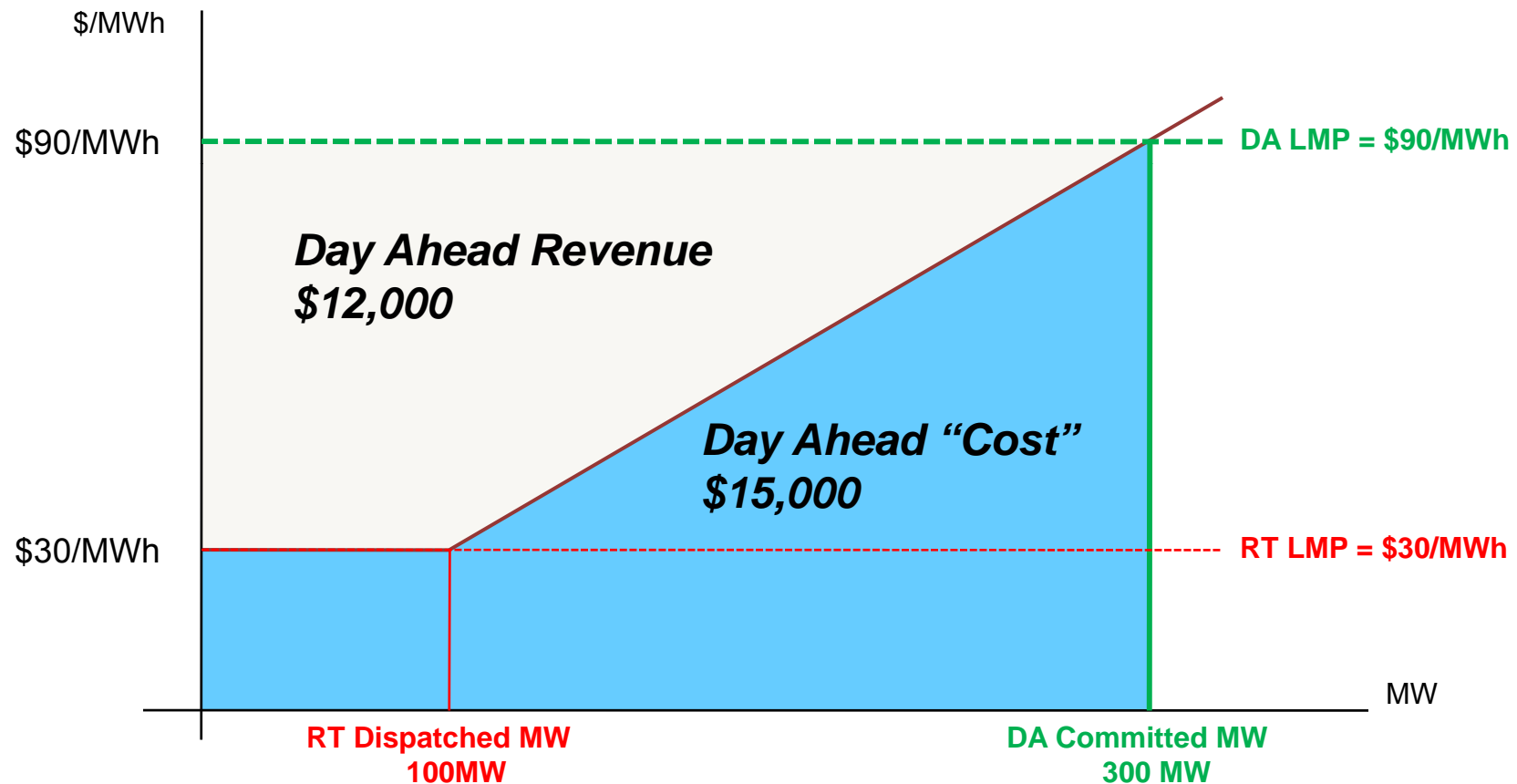
- **Day Ahead Market**
 - Provides an opportunity for resources and load to lock-in to a forward price to eliminate exposure to potentially volatile real-time prices
 - Is solved by scheduling supply to meet cleared demand (not load)
 - Supply is committed based on offer parameters and scheduling costs
 - Virtual bids (incs/decs) participate and help drive consistency with real-time prices
 - Solution is a financially binding commit to purchase or sell energy the next day based on Day Ahead MWs and LMPs

- **Unit Dispatch System (UDS)**

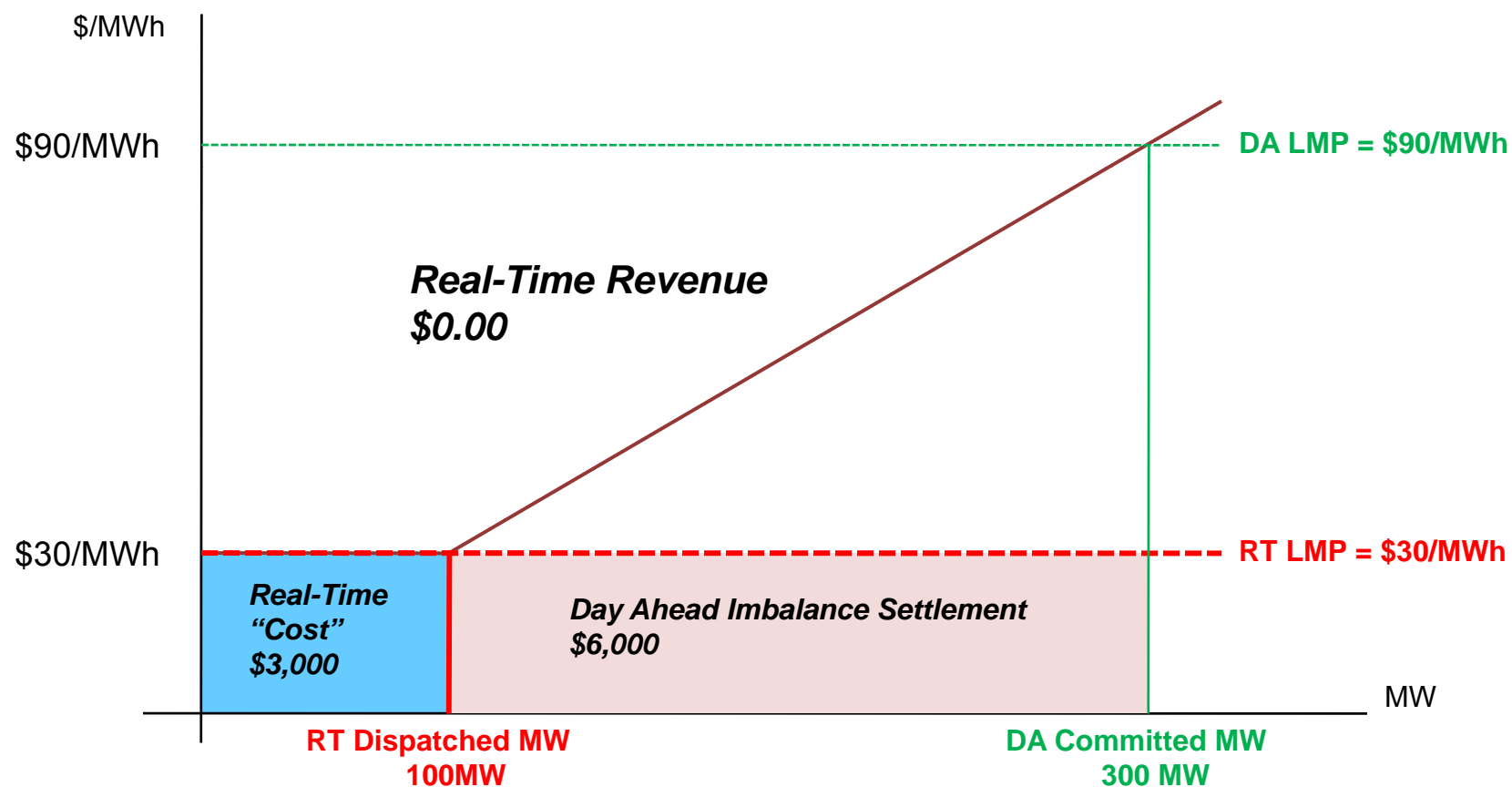
- On average, every 5-minutes PJM re-dispatches generators to meet system needs
 - Load
 - Reserves
 - Congestion
- Dispatch solution provides the most economic solution to meet these system needs while respecting transmission system limitations and bid-in resource parameters
- The dispatch signal is a directive representing the optimal output for a resource

- **Locational Marginal Prices (LMPs)**
 - Based on responses to the dispatch solution and current system conditions, PJM calculates 5-minute LMPs for each bus, hub, zone, aggregate and interface
 - Cost to serve load, congestion & losses
 - LMPs are set by the “marginal” resources
 - Only resources following dispatch can set LMP
 - Based on the actual flow of energy
 - Real-Time LMPs are used to settle imbalances from the Day Ahead Market

- **Generator A is committed Day Ahead**
 - Below is Generator A's cost curve showing commitments



- Then dispatched down in **Real-Time**
 - Below is Generator A's cost curve showing commitments



- **Generator A's Net Position**

- *DA Settlement = \$90/MWh * 300 MW = **\$27,000***

- “Cost = \$15,000” (this is actually \$0)

- Revenue = \$12,000

- ***Imbalance = \$9,000***

- Actual Cost = \$3,000

- Imbalance = \$6,000

- Revenue = \$0.00

- **Total Revenues = DA Settlement - Imbalance**

- **\$27,000 - \$9,000 = +\$18,000**

- **Generator A's Net Position**

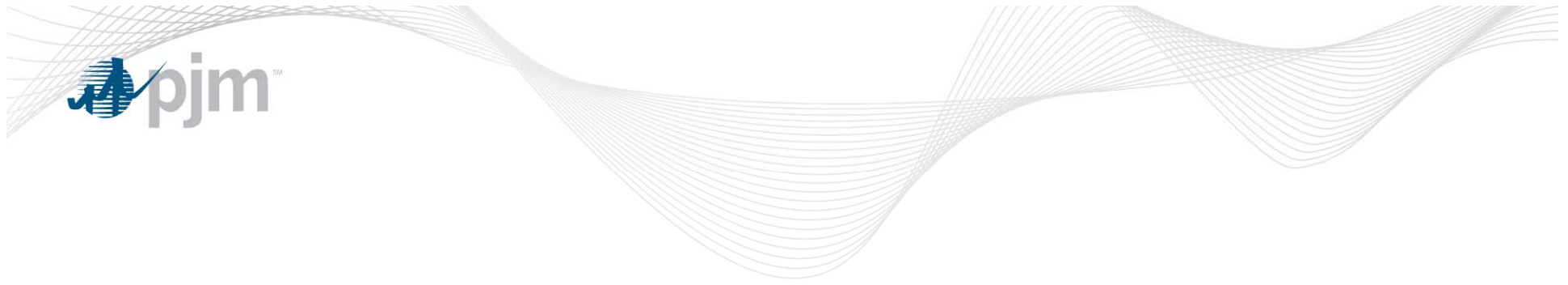
- *DA Settlement = \$90/MWh * 300 MW = **\$27,000***
 - “Cost = \$15,000” (this is actually \$0)
 - Revenue = \$12,000
- ***Imbalance = \$15,000***
 - **Actual Cost = \$15,000**
 - **Imbalance = \$0.00**
 - Revenue = \$0.00
- Total Revenues = DA Settlement - Imbalance
 - \$27,000 - \$15,000 = **+\$12,000**
- Exposed to balancing operating reserve charges

- Synchronized Reserve
 - Product used to recover ACE within 10 minutes of contingency
 - Hourly Market cleared and priced one hour prior to the operating
 - Jointly optimized with regulation commitments based on forecasted system conditions
 - Assignments committed through eMKT
 - Resources are paid the higher of the clearing price or real-time cost to provide

- Regulation
 - Product used to maintain ACE throughout the operating hour
 - Hourly Market cleared and priced one hour prior to the operating
 - Jointly optimized with regulation commitments based on forecasted system conditions
 - Assignments committed through eMKT
 - Resources are paid the higher of the clearing price or real-time cost to provide

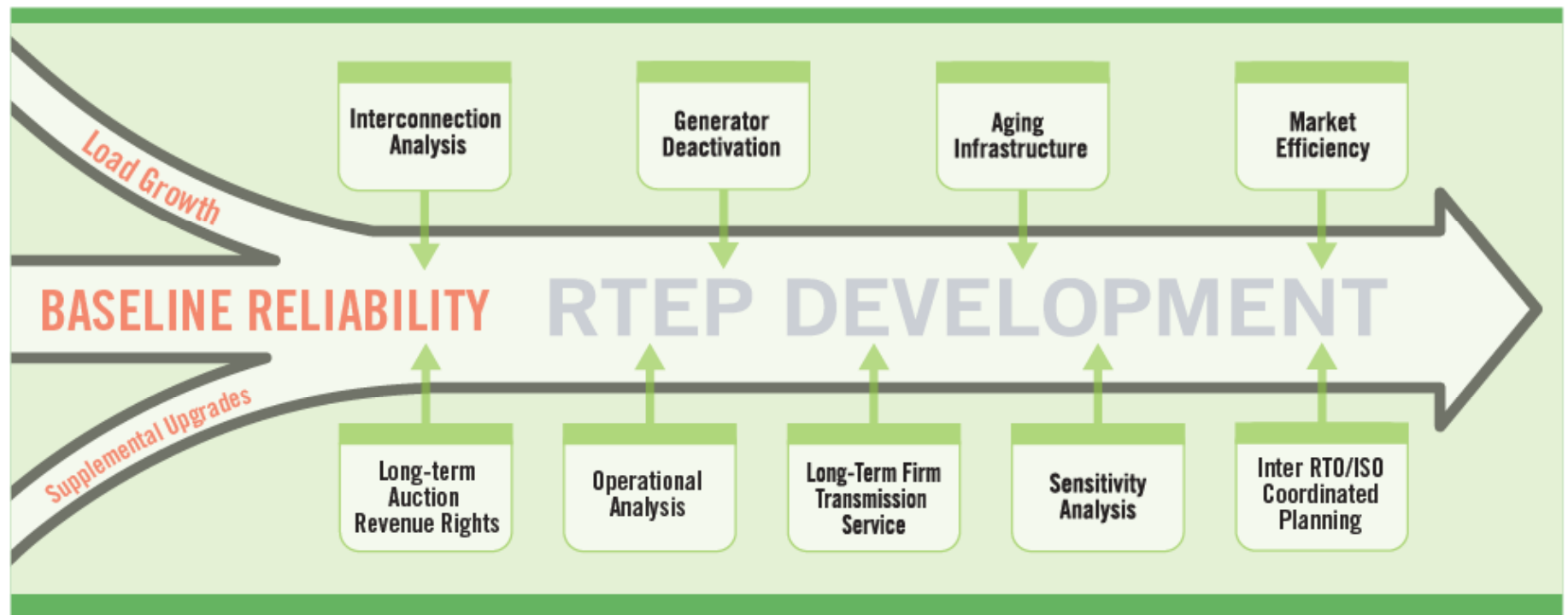
- SPWG is currently discussing modifications to the real-time market architecture
 - Real-Time joint optimization of energy and reserves similar to MISO, ISONE, NYISO
 - Implementation of an Operating Reserve Demand Curve to moderate prices
 - Implementation of a Primary Reserve Market
 - Goals
 - Improve operational reliability
 - Improve price performance during peak conditions
 - 5-minute pricing of Ancillary Services
- Planned “go-live” on October 1, 2010

<http://www.pjm.com/committees-and-groups/working-groups/spwg.aspx>



Generator Interconnection Process

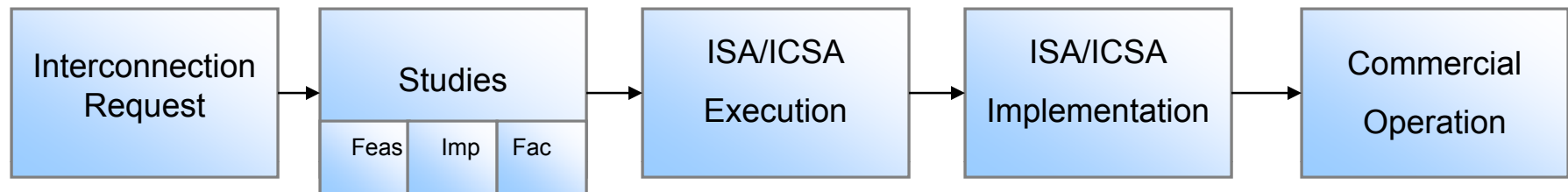
- Ongoing and cyclical
- 15 year planning horizon
- RTEP issued each year
- Baseline Analysis
- Interconnection Analysis
- Coordinated Planning w/ adjacent areas



- Deliverability of generators currently in service
 - Firm delivery rights: grandfather as capacity with ATSI responsible to reinforce overloads as baseline upgrades
 - Non-firm delivery rights: grandfather as energy with ATSI responsible to reinforce overloads as baseline upgrades

- Deliverability of generators with executed agreements but not yet in service
 - Test for deliverability as a group
 - If any are found not deliverable, then put all generators in PJM New Services Queue for study

- Proposed generation in ATSI territory
 - Determine time and date for receipt of the request for study in the MISO queue and insert the generator in the PJM New Services Queue according to this date.
 - Perform all necessary studies according to the PJM Interconnection Studies process (Feasibility Study, System Impact Study, Facilities Study)



- **Interconnection Process**
 - Planning Studies
 - Agreements

- Engineering, construction and energization activities
 - System upgrades
 - New generation projects
 - Upgrades
- Integrates RTEP projects from PJM Planning into PJM Operations and Markets
 - Outage Coordination
 - Model Coordination
 - Markets Interface

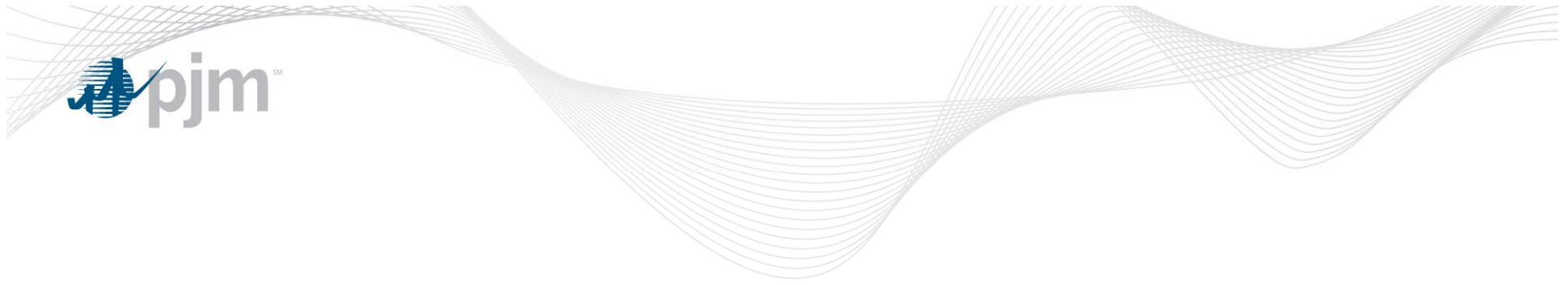




Integration of Generation Resources into PJM

- Integration into PJM Operations and Markets
 - Modeling of Generation Facility and Switchyard
 - SCADA / Metering
 - eMTR and eMKT Account set-up and implementation
 - Capacity Credits
 - Operational Requirements (Manual 14D)
 - Wind Farm Specific Requirements
 - Met tower data and Wind turbine availability reporting
 - Inputs into Wind Forecasting Tool
 - Issues related to ownership shares or changes

- Generator Deactivation process part of Manual 14D
 - 90 day advanced notice in writing to PJM
 - 2 year advanced notice if Black Start unit
- Analysis performed to determine impacts to transmission system
 - No impacts – generator can retire
 - System impacts
 - Determine time to complete system upgrades
 - System upgrades become responsibility of Transmission Owner
 - If upgrades cannot be completed in time – generator can be asked to continue to operate until upgrades are complete
 - See Manual 14D for specifics on cost recovery for generator required to continue to operate



RPM Transition



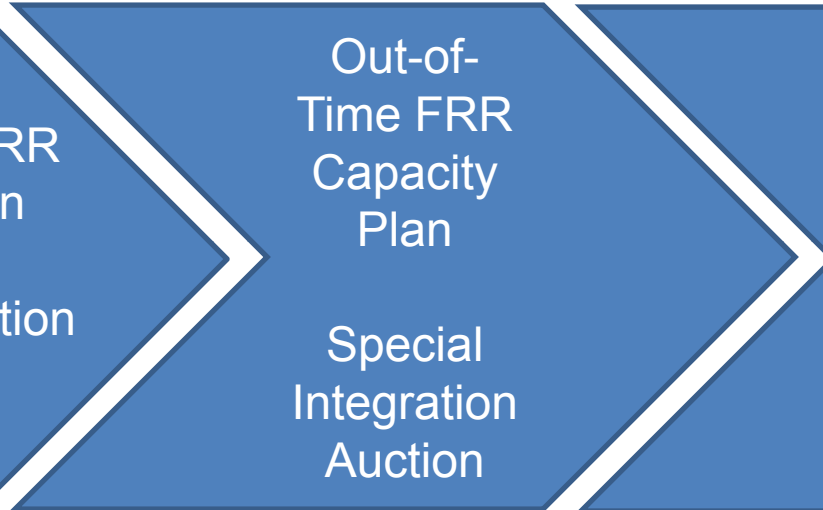
Integration into PJM's Capacity Market

- ATSI zone integration into PJM on June 1, 2011, start of 2011/12 Delivery Year
- ATSI Utilities to submit out-of-time FRR Capacity Plans for 2011/12 DY and 2012/13 DY
 - RPM Auctions for 2011/12 DY and 2012/13 DY conducted in May 2008 and May 2009, respectively
- Capacity procured for ATSI zone through regular RPM schedule for 2013/14 DY
 - RPM Auction for 2013/2014 DY to be conducted in May 2010

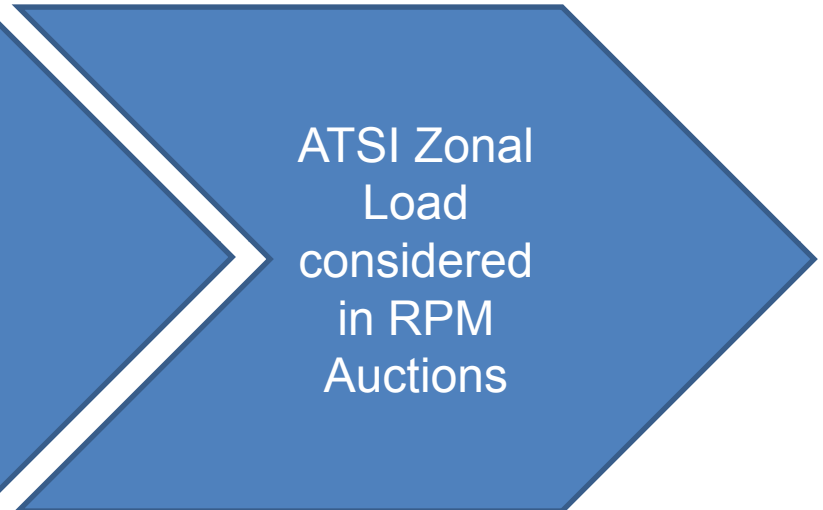
2011/2012 DY



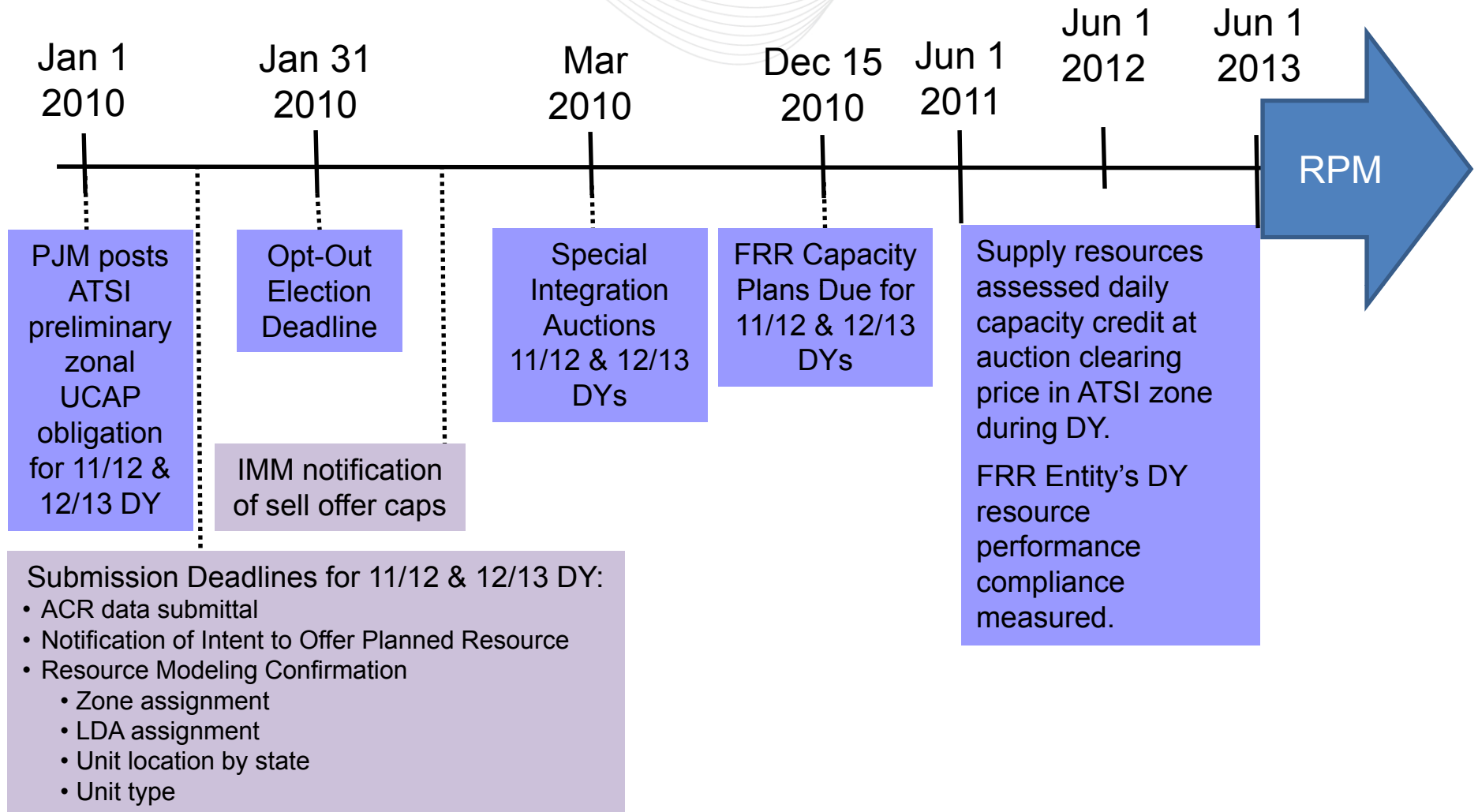
2012/2013 DY



2013/2014 DY & beyond



Transition Timeline 2011/12 & 2012/13 Delivery Years



- ATSI Utilities to submit out-of-time FRR Capacity Plans for each DY by December 15, 2010
- ATSI Utilities FRR plans must commit enough capacity to cover the UCAP obligation for the entire ATSI zone minus “opt-out” load
- Capacity to be procured through special integration auctions
 - If special integration auctions do not procure sufficient capacity to meet obligation then ATSI Utilities to procure balance through bilateral arrangements
 - ATSI Utilities to enter into bilateral contracts with supply resources that clear in special integration auctions
- ATSI Utilities pay capacity suppliers at auction clearing price

- Two Special Integration Auctions, one for each DY, to be conducted in March 2010
- Special Integration Auctions for 11/12 & 12/13 DY to be conducted at the same time
- Sell Offers submitted via eRPM system by suppliers with available capacity will establish supply curve
- Vertical Demand Curve based on the remaining amount of zonal UCAP obligation (after any opt-out load is removed)

Demand in the special integration auctions is based on Preliminary Zonal UCAP Obligation for the ATSI zone, adjusted to remove opt-out load

- Preliminary Zonal UCAP Obligation based on Preliminary Zonal Peak Load Forecast and Forecast Pool Requirement (FPR)
 - 11/12 DY FPR = 1.0833
 - 12/13 DY FPR = 1.0872
- Preliminary Zonal UCAP Obligation for each DY to be posted by January 1, 2010

May be conducted at any time prior to DY

Feb 1 2010 Mar 2010 Apr 2010 May 2010 Sept* 2011 Jul* 2012 Feb 2013 Jun 1 2013 May 31 2014

PJM posts planning parameters for 13/14 DY BRA

Base Residual Auction

IMM notification of sell offer caps

1st Incremental Auction

2nd Incremental Auction

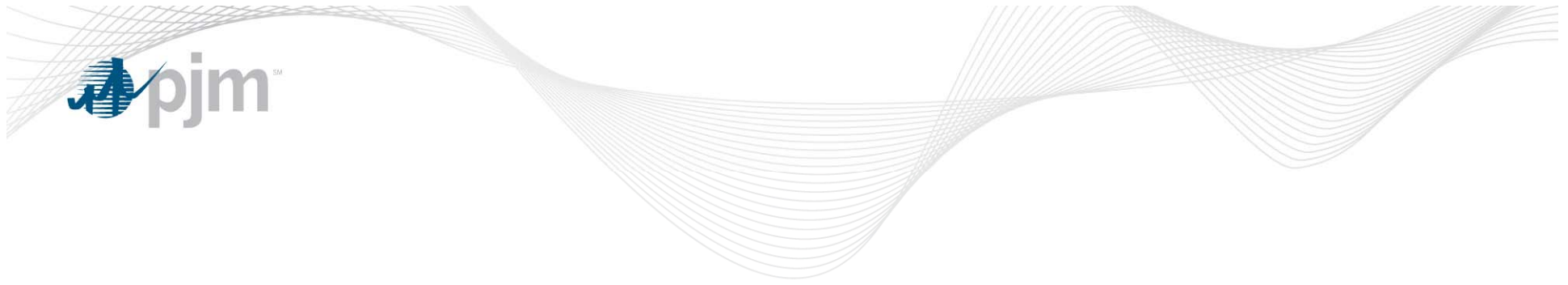
3rd Incremental Auction

Conditional Incremental Auction

Supply resources provided daily auction credit under RPM
Resource Provider's DY resource performance compliance measured.

Submission Deadlines for 13/14 DY:
 • ACR data submittal
 • Notification of Intent to Offer Planned Resource

** CMEC proposal to change 1st IA from June to Sept and 2nd IA from April to July.*



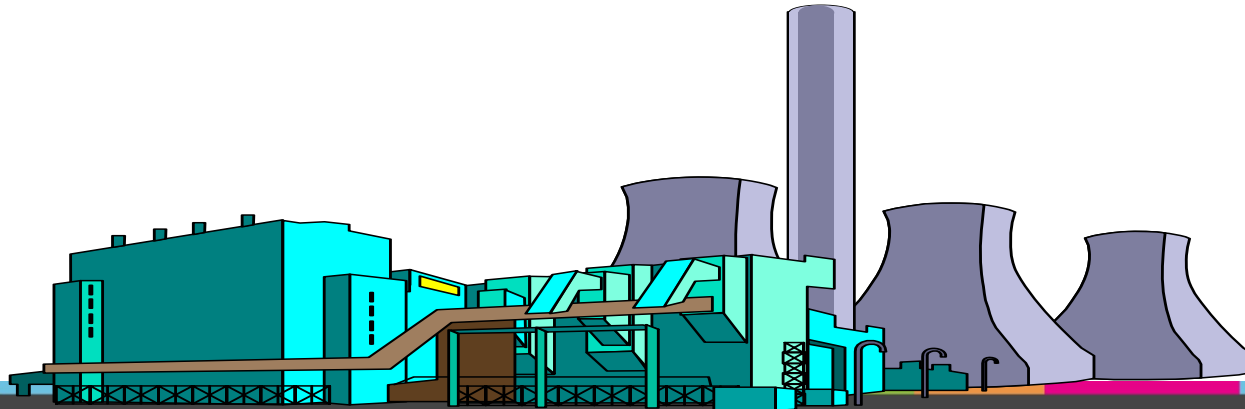
Capacity Testing

INSTALLED CAPACITY in PJM is expressed in terms of **Summer Rating** and **Winter Rating** in MW of all generating units which participate in the markets as capacity resources.

- **eRPM** contains the official record of summer and winter ratings as entered by the owner/operators of each unit with PJM approved “capmod” operations.

Summer Rating is the basis for unforced capacity in the markets as well as injection rights and must be verified by test once every summer season.

Winter Rating is used for reliability studies and must be verified by test once every winter season unless granted an exception by PJM



- **Summer Tests** must be conducted between June 1 and August 31.
- **Winter Tests** must be conducted between December 1 and February 28 (or 29).
- **Out-of-Period Tests** may be entered after the end of each test window to correct deficiencies.
- Hydro units are required to test once per year at any time.
- Intermittent resources (wind, solar) are not subject to a testing requirement

- Nuclear, Fossil Steam, Combined Cycle
 - Two Hours
- Hydro, CT (simple cycle), Diesel
 - One Hour

Test duration is sufficient to allow each unit type to achieve stable operating conditions

Tests for Combined Cycle and CT units must be temperature corrected to the average site temperature at the date and time of the PJM Summer peak over a 15 year period.



PJM eGADS

Verification Test Data Reporting

Claimed Capacity is entered by PJM from eRPM files.

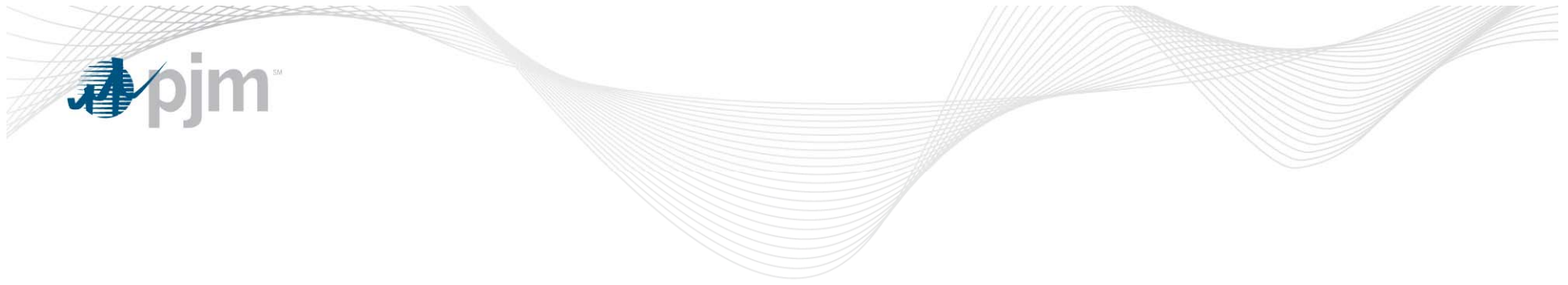
Other required fields are entered by the user.

Final result is calculated automatically.

PJM eGADS User or Test User account is required

- *A Forced Derating must be entered into the eGADS data for the unit in the amount of the test shortfall*
 - The event begins at the start of the test window
(June 1 for Summer and December 1 for Winter)
 - The event continues until one of the following occurs:
 - The start time of a successful out-of-period test.
 - The unit capacity in eRPM is reduced to match the test result with a “capmod” operation.
 - The next capacity test window begins.

- PJM Manual 10 Pre-Scheduling Operations
Section 6 – Winter Net Capability Test Exemption
- PJM Manual 18 – PJM Capacity Market
Section 8 – Resource Performance Assessments
- PJM Manual 21 – Rules and Procedures for Determination of Generating Capability



Compliance Activities

- Purpose
- Assumptions
- Roles and Responsibilities
- Compliance Integration Timeline
- Compliance Project Team

- Provide an overview of the compliance activities that will be occurring as part of the ATSI integration into PJM's wholesale energy and ancillary service markets

- Complete all compliance activities 90 days prior to integration
 - March 1st 2011
 - Currently reaching out to all participants
 - Generation owners
 - Load serving entities
 - Regulatory entities
- Regional and NERC approvals will take no less than 12 months

- PJM will need to complete independent regional certifications for the integration
- ATSI processes and procedures need to be aligned with existing PJM processes and procedures
 - Possible modification to various PJM processes and procedures
 - Many decisions interrelated
 - Registration decisions will impact processes and procedures

- During on-going meetings with the impacted stakeholders PJM will
 - Work with stakeholders to identify and implement changes required
 - Manuals
 - Agreements
 - Registration
 - Ensure internal driven changes identified by other teams during the integration are properly documented
- PJM will meet with ATSI and other impacted stakeholders to
 - Discuss recent audits and address possible weaknesses during integration period

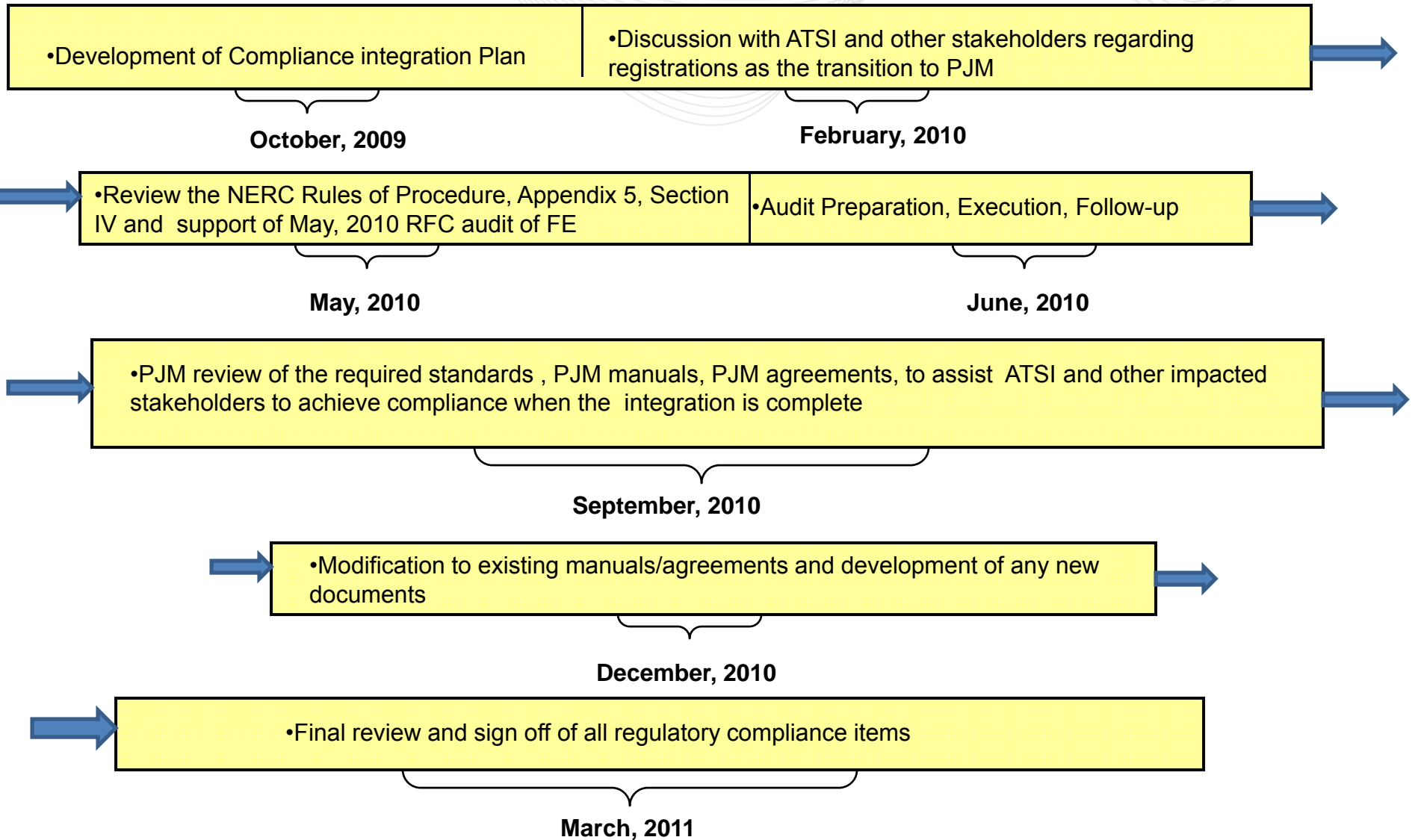


Roles and Responsibilities

- Stakeholders
 - Communicate issues/concerns to PJM teams
 - Compliance team contact information included as part of this presentation



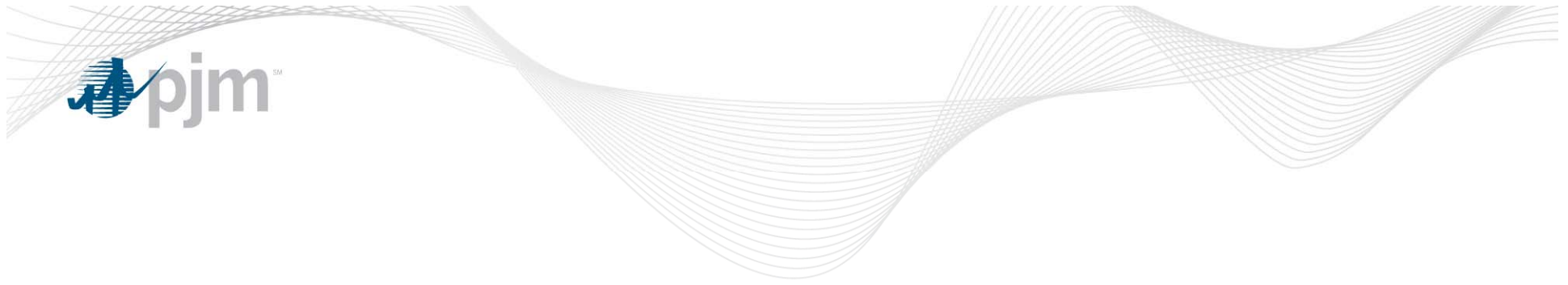
Compliance Integration Timeline





Compliance Project Team

- Patrick Brown: 610-666-4597 brownp@pjm.com
- Bill Harm: 610-666-8868 harm@pjm.com
- Cathy Wesley: 610-666-4628 weslec@pjm.com



Stakeholder Training

- A series of training programs will be held within the ATSI footprint to prepare stakeholders for integration
 - Tentatively targeted for Aug 2010 – March 2011
 - Cleveland, Akron and Columbus locations
- Additional training sessions will be available in other parts of the PJM footprint, as well as online
- Training is targeted towards three main groups of stakeholders:
 - Transmission: owners, operators and engineering support staff
 - Generation: owners, operators, schedulers, power marketers, traders
 - Load serving entities

- All generation operators must be PJM certified within 1 year of integration
 - Must work under direct supervision of PJM certified operator prior to certification
- Market Operations Center (MOC) program is designed to
 - Provide a basic level of knowledge on topics critical to gen dispatch in PJM
 - Help prepare gen operators for PJM certification exam
 - Prepare traders and schedulers for participation in PJM markets
- MOC program qualifies for NERC Continuing Education Hours

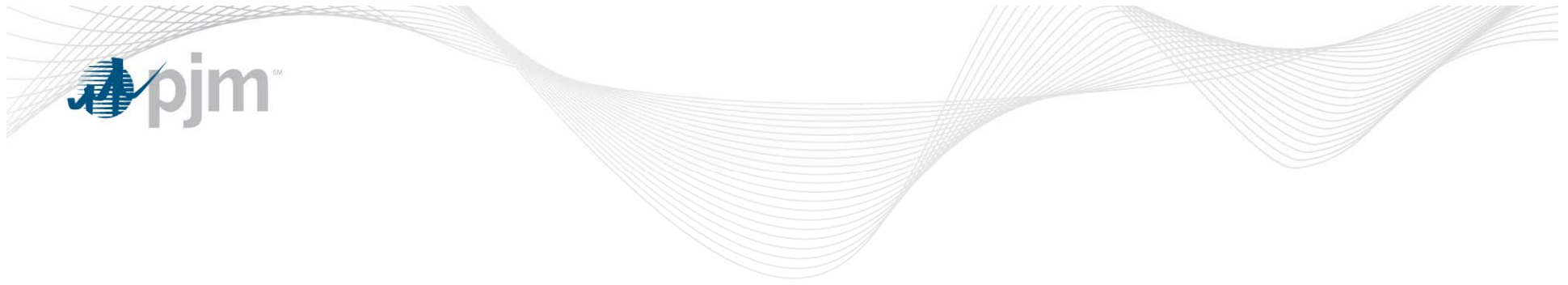
- MOC program topics include:
 - Locational Marginal Price
 - Generation Outage Scheduling
 - Generation Control
 - Scheduling Process for Generation
 - Ancillary Service Markets
 - Transactions
 - Emergency Procedures
 - System Restoration
 - Market Settlements
 - Applicable eTools
 - eDART, eDATA, eMKT, eSchedules, OASIS, EES

- Transmission and Generation Operators must also meet PJM training requirements
 - Complete LCC/MOC or Interconnection Training Program (ITP) program within 1 year of integration
 - New operators must complete ITP program within 2 years of integration
 - Defined as operator with less than 2 years of prior experience participating in real time operations before assignment of PJM real time duties
 - ITP program is offered each fall and winter in the area of PJM's campus

- Program designed to provide Load Serving Entities and Marketers with the information necessary to conduct business in PJM
 - Topics include:
 - Locational Marginal Price
 - Financial Transmission Rights
 - Energy Transactions
 - Capacity Obligations and RPM
 - Two-Settlement (Demand Perspective)
 - Market Settlements
 - Applicable eTools
 - eMKT, eFTR, OASIS, EES, eSchedules, eRPM
 - Market Examples

- **Reliability Pricing Model**
 - Introduces participants to RPM and covers demand and supply in RPM, RPM auctions, LSE obligations, resource performance assessments and settlements
 - Special attention focused on detail of special integration auctions
- **Market Settlements 301**
 - Provides details of the market settlements process and the components of a typical PJM invoice. The program describes the various possible charges and credits and review examples on spot market interchange calculations.

- **PJM 101**
 - Introduces participants to PJM's markets and operations models. Includes presentations on the PJM markets and system operations, as well as market settlements, capacity and transmission expansion planning.
- **Locational Marginal Pricing 101**
 - Covers definition of LMP, 5-bus model examples, LMP verification & posting process
- **Follow-up one-on-one training, as necessary**
- **Other regularly scheduled training**
 - Includes FTR/ARR annual training, eLRS
 - PJM Training web page: <http://www.pjm.com/training.aspx>



Participant Readiness Activities

The participant readiness effort focuses on preparing companies impacted by the ATSI integration for participation in PJM's markets

The objectives of this effort are:

- Provide new customers with a central point of contact (Client Manager)
- Provide materials to inform and educate new customers about PJM requirements
- Provide and define criteria that promotes new customer readiness
- Provide checkpoints to facilitate the provision of necessary information to PJM

The integration project team is actively working to identify and contact companies who will be impacted by the ATSI Market Integration.

- PJM Client Managers will be contacting impacted companies to discuss the type of activity they will conduct in PJM and understand questions and concerns
- Client Managers will provide a checklist to help new customers identify integration readiness tasks and data required by PJM

The central tool to the readiness process is the Checklist, which contains a list of base requirements that PJM has identified as central to a successful integration.



Each checklist contains a breakdown of readiness topics, including:

- Administrative Tasks (e.g. membership)
- Education (e.g. PJM process and application training)
- Data Submission (e.g. generator data, meter data)
- Application Changes (e.g. scheduling system changes)
- Technical Changes (e.g. connectivity, XML submission)



Readiness Checklist

A generic checklist has been created for six general participant types. Each checklist contains comprehensive information on tasks required and capabilities needed to integrate with PJM.

- List have been created for:
- LSEs
 - Marketers
 - Municipalities
 - Generators
 - Transmission Owners
 - Demand Resources

Participant Readiness Checklists		
Activity	Sub-activity	Action(s)
Load Serving Entities (LSEs)		
Administrative	Membership and Agreements (Level 1)	<p>The following is a list of PJM membership requirements:</p> <ul style="list-style-type: none"> ? Become a member of PJM ? Sign the PJM Reliability Assurance Agreement (RAA) ? Submit Network Transmission Service Agreement for Retail Load Serving Entities ? Reviewed OATT ? Meet your daily unforced capacity obligation or be subject to deficiency charges ? Sign a Transmission Service Enabling Agreement ? Sign s Service agreement for Firm and/or Non-Firm Point-to-Point Transmission Service ? Complete the credit application <p>Applications: The appropriate resources within your organization have learned how to:</p> <ul style="list-style-type: none"> ? Obtain User IDs/Passwords for required users of each PJM application ? Account Managers and users have learned how to use CAM
		<p>Business Procedures: The appropriate resources within your organization have:</p> <ul style="list-style-type: none"> ? Obtained an understanding of PJMs scheduling process for generation and load ? Obtained an understanding of the PJM Network Model ? Obtained an understanding of LMP and LMP Pricing Mechanisms including pricing hubs and other aggregates

The Readiness Checklist will be quantified to facilitate the assessment of Participant Readiness.

Each section of the checklist is broken into levels of readiness:



- **Level One** – Required criteria for successful implementation
- **Level Two** – Meeting this criteria will improve the success of the integration
- **Level Three** – Meeting this criteria will enhance the integration

- Client Managers will conduct an initial meeting with primary contacts from each company (Reps) to review and update a Readiness Checklist.
- Client Managers and Reps will work together to modify the checklist to meet the specific needs of the participant.
- Reps and Client Managers will speak on a regular basis to determine status of readiness tasks.
- The status process will also help PJM to identify key issues and mitigate risks on a week-to-week basis.
- Status will be reported throughout the readiness process to the individual participant and the PJM RTO Integration team.
- *The Rep can use the checklist as one tool for communicating status internally.*

There are several resources companies can use to prepare to integrate into PJM.

- Market Integration Website
 - (<http://www.pjm.com/markets-and-operations/atsi-integration.aspx>)
 - White papers
 - FAQs
 - Market Integration Updates
 - New Member Readiness Guide
- PJM Manuals (www.pjm.com)
- Committees and Working Groups
- Training Sessions
- Market Trials (Apr – May 2011)



Client Managers:

Jim Kirby:	610-666-8872	kirbyjw@pjm.com
Glenn Weiss:	610-666-8855	weissgc@pjm.com

Customer Relations Hotline

866-400-8980 custsvc@pjm.com