The Brattle Group

Second RPM Performance Assessment and CONE Study

Prepared for:
PJM Interconnection

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Study Purpose and Scope

Purpose

- *The Brattle Group* was commissioned by PJM to conduct a performance assessment of RPM, as required periodically under the Tariff

Scope

- A review of all auctions to assess the track record of RPM in attracting and retaining sufficient capacity to meet resource adequacy requirements
- Stakeholder interviews to identify top concerns
- An engineering-cost estimate of CONE for each of five CONE Areas
- An evaluation of individual RPM design elements, including the VRR curve, the E&AS offset methodology, and other elements identified by stakeholders
- Development of recommendations for possible modifications (if any) to improve the effectiveness of RPM

Primary Finding: RPM has Achieved Design Objectives

- RPM has achieved resource adequacy
  - RPM has attracted and retained sufficient capacity to meet or exceed reliability requirements in the RTO and every LDA
  - Moderate capacity deficits occurred in some LDAs in early years due to pre-RPM conditions, but *no shortages anywhere* in the last 4 BRAs
- Prices have been consistent with market conditions
  - Lower prices (below Net CONE) under excess supply conditions
  - Higher prices under tighter supply conditions, but still below Net CONE in recent auctions
- RPM has reduced costs by fostering competition
  - Generally level playing field has reduced costs by attracting investments in low-cost supplies from demand response, efficiency, and uprates
- RPM has enabled cost-effective response to environmental rules
  - Facilitated economically efficient tradeoffs among investment in environmental retrofits, retirement, and replacement with lower-cost alternative supplies

Some Concerns Inconsistent with Evidence

Stakeholders raised valid concerns. However, several major criticisms of RPM are not supported by evidence available to date, including:

- “RPM prices are too high”
  - Prices below annualized cost of new generation in even the highest-priced LDAs; will have to increase to sustain resource adequacy in the long run
  - Locational price differences consistent with transmission constraints and fundamentals
- “RPM doesn’t support new generation of the right type in the right places”
  - Locational resource adequacy achieved with lower-cost resources; substantial additions from demand resources and uprates
  - New generation has been built under RPM: 4.8 GW of committed additions (excludes FRR capacity & territory expansions)
  - Additional new generation was not needed for resource adequacy and would have been uneconomic at prices observed to date
- “RPM cannot maintain reliability in the face of environmental retirements”
  - So far, RPM facilitated adequate and economic retrofits and replacement capacity; BRA procurement in excess of target in every LDA for 2014/15 when the HAP MACT regulation will come into force; also accommodated MD Healthy Air Act in 2009-11 in SWMAAC

Recommendations to Increase Transparency and Stability

Concern: Excess Uncertainty within LDAs May Deter Investment

- Market participants found RPM prices to be volatile and unpredictable
- Price volatility has been driven by:
  - **Market Fundamentals** – not a concern, prices should move with market fundamentals
  - **Previous Design Improvements** – some price changes from prior RPM design adjustments (i.e., more LDAs, eliminate ILR); not a concern going forward
  - **Ongoing Administrative Uncertainties** – uncertainty about administrative parameters exacerbates price volatility and unpredictability

Recommendations

- Increase transparency and stability of administrative parameters
  - **Stabilize CETL**: planning deadband; identify limiting elements, facilitate upgrades
  - **Increase CETL transparency**: provide model and 5&10-yr CETL outlook (w/ RTEP)
  - **Make load forecast process and uncertainty range more transparent**
- Facilitate hedging and long-term price transparency by developing voluntary centralized auctions or an over-the-counter exchange for long-term capacity products (already in discussion)

Recommended Safeguards Against Future Challenges

While RPM has met its design goals to date, we have identified RPM performance risks that should be addressed to ensure resource adequacy

VRR Curve Shape

- The cap of the VRR curve (point "a") may be too low, esp. w/historic E&AS:
  - Probabilistic simulations identified poor reliability outcomes for historic E&AS (due to risk of anomalously high E&AS values)
  - Also concerned that low caps in some LDAs could deter needed offers for generation with costs > cap due to large differences between actual and administrative Net CONE
- We recommend PJM and stakeholders consider:
  - Raise point "a" to at least 0.5xCONE above point "b" (possibly to 1.0xCONE above "b") to avoid collapsing the VRR curve and deterring needed offers when below reliability target – especially if a normalized, forward-looking offset cannot be developed before the next BRA
  - Confirm that Net CONE estimates cannot be less than zero for purpose of determining points "b" and "c" of the VRR curve
  - Renew effort to develop a normalized, forward-looking or equilibrium E&AS offset

E&AS Offset Calibration

- Actual E&AS below administrative E&AS offset (for generators similar to the reference unit) in some CONE areas
  - In EMAAC, calculated E&AS offsets about $20/kW-yr higher than actual margins
  - Recommend calibrating administrative E&AS calculation to historic observations

Recommended Safeguards (cont.)

Proactive LDA Modeling

- More proactive definition of new LDAs if large amounts of supply may be at risk of retiring or not clearing
- Model additional LDAs in incremental auctions if insufficient capacity cleared the BRA (to ensure reliability if it were to retire)

2.5% Short-Term Procurement Target

- Maintain the 2.5% "holdback" only for Limited resources (sufficient unmitigated MW), not to Annual and Extended Summer resources (little unmitigated MW, and annual resources less likely to be procured on a short-term basis)

Resource Verification

- Audit DR for contractual and physical ability to respond as often and seasonally as claimed (esp. for new products); conduct random testing

MOPR Exemptions

- Better support competitive entry through bilateral and self-supply arrangements by establishing clear exemptions to MOPR for offers that are based on a non-discriminatory procurement or that do not serve net-short buyers

CONE Study

Conducted Engineering Cost Study

- Estimates based on plant-proper engineering cost estimates developed by the EPC contractor CH2M HILL and FOM cost estimates from O&M service provider Wood Group

Calculated level-real and level-nominal CONE values

- Level-real reflects an expected trajectory of future revenues growing with increases in the net cost of new capacity (historically, the net cost of capacity grew approx. with general inflation: average CT cost inflation over the last 20 years exceeded CPI by 60 bpts while heat rate improvements saved approximately 50 bpts)
- Recommend transitioning to level-real for setting CONE, but *only* if our recommended safeguards regarding VRR curve shape and E&AS offset are adopted; otherwise, identified performance risks would increase
- Recommend using level-real for MOPR purposes

CONE Study Summary of Results

Simple Cycle CONE

CONE Area	*Brattle* Estimate		2014/15 CT CONE
	Level Real *(2015$/kW-y)*	Level Nominal *(2015$/kW-y)*	Escalated at CPI for 1 Year *(2015$/kW-y)*
1 Eastern MAAC	$111.9	$133.9	$142.1
2 Southwest MAAC	$103.3	$123.6	$131.4
3 Rest of RTO	$103.1	$123.4	$135.0
4 Western MAAC	$108.6	$130.0	$131.4
5 Dominion	$92.8	$111.0	$131.5

Combined Cycle CONE

CONE Area	*Brattle* Estimate		2014/15 CC CONE
	Level Real *(2015$/kW-y)*	Level Nominal *(2015$/kW-y)*	Escalated at CPI for 1 Year *(2015$/kW-y)*
1 Eastern MAAC	$140.5	$168.1	$179.6
2 Southwest MAAC	$123.3	$147.5	$158.7
3 Rest of RTO	$135.5	$162.1	$168.5
4 Western MAAC	$135.1	$161.8	$158.7
5 Dominion	$120.2	$143.8	$158.7

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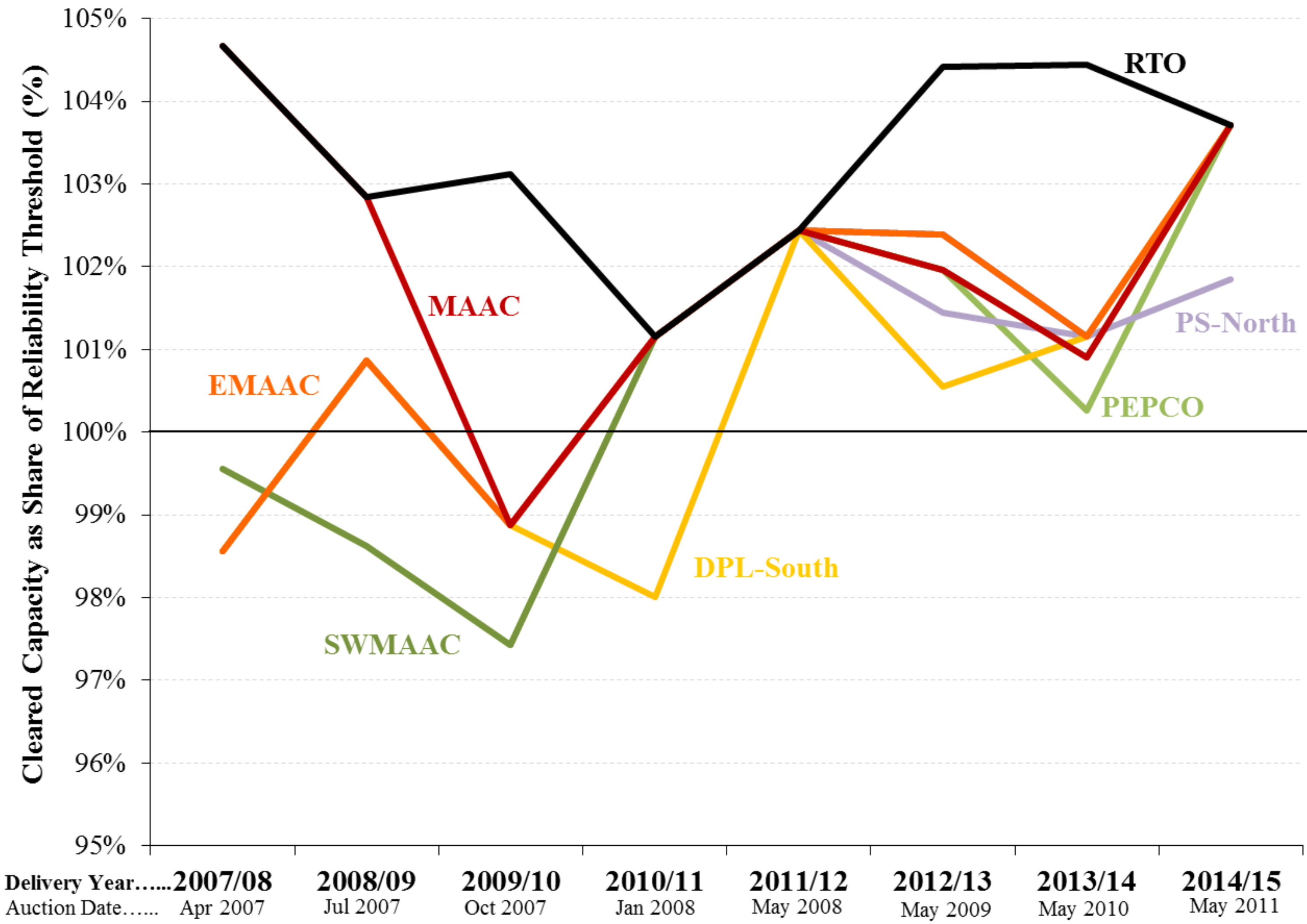
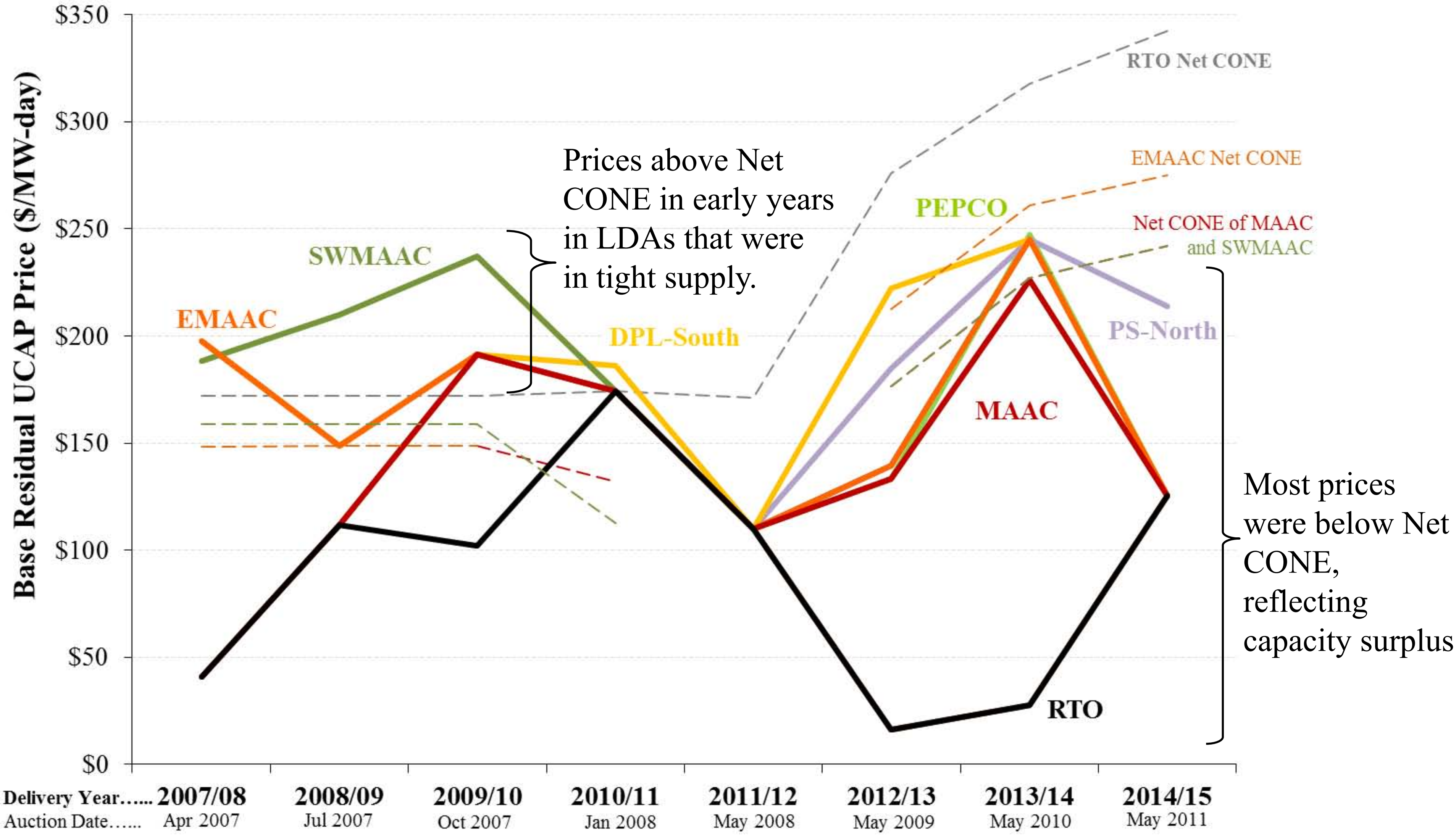
Clearing Quantities Relative to Reliability Targets



All locations cleared with surplus capacity since 2011/12 when forward period became 3 years

Initial BRAs cleared moderate capacity deficits in some LDAs related to pre-RPM conditions

Base Residual Auction Prices

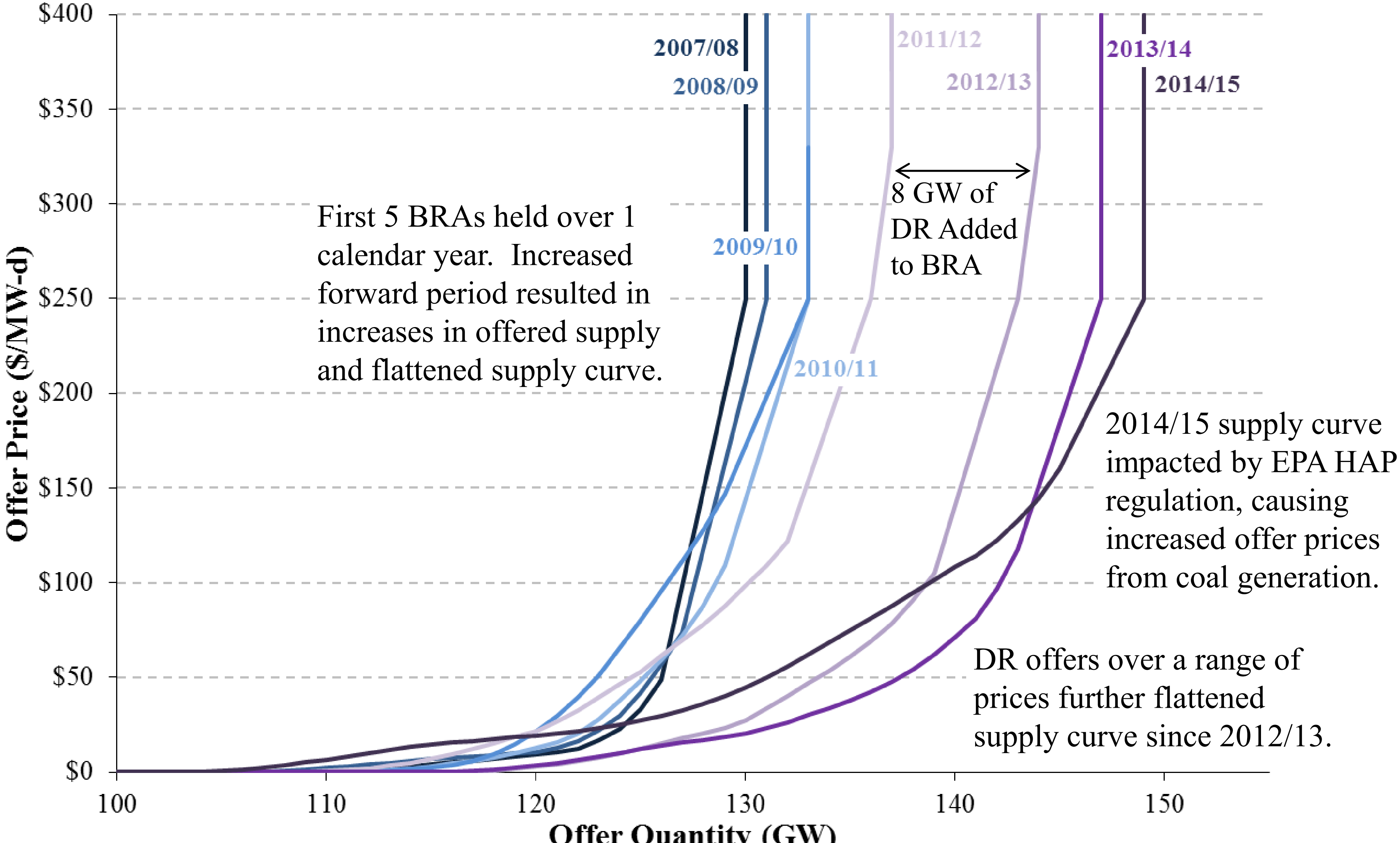


Drivers of Major BRA Price Changes

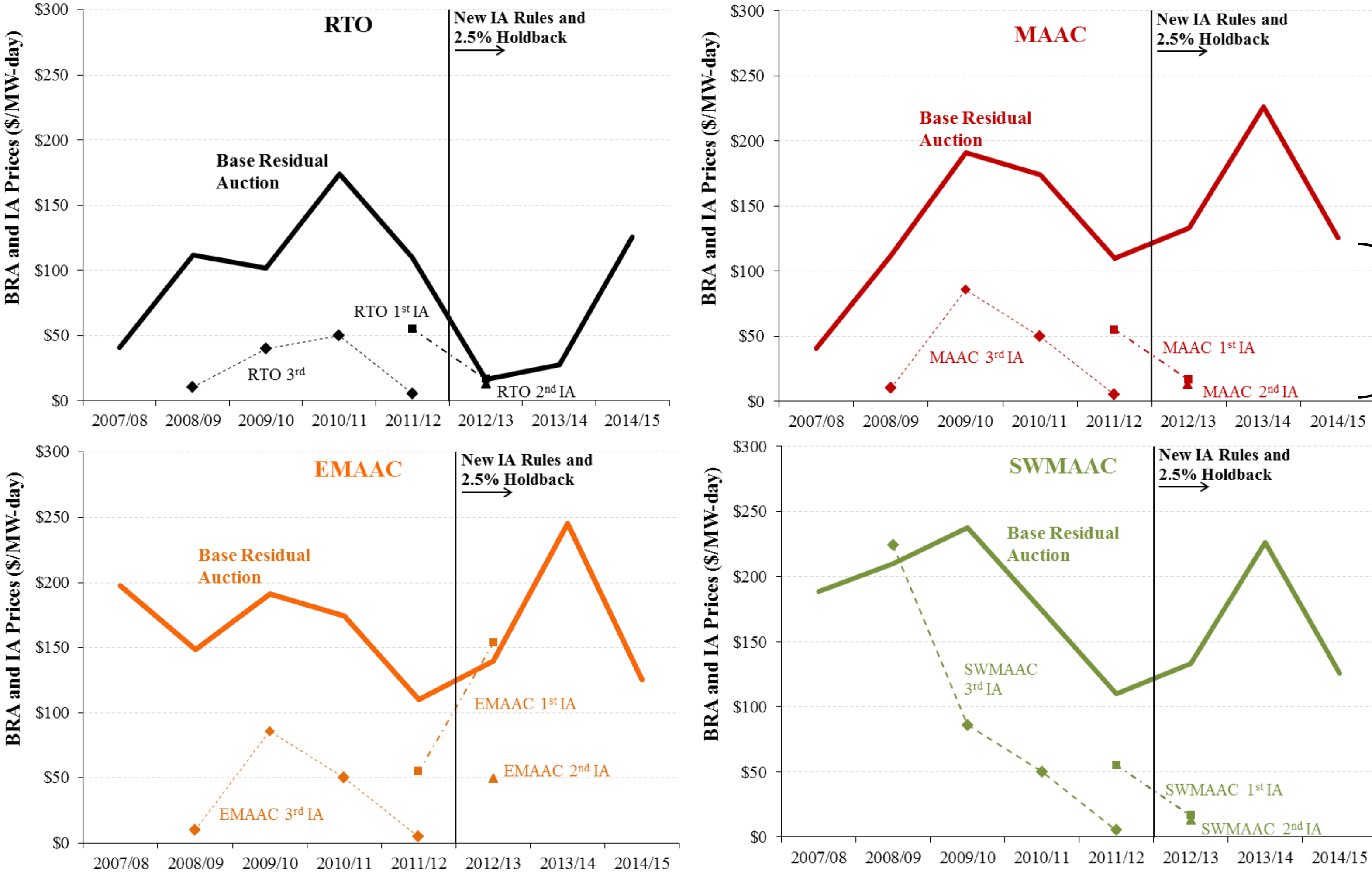
Year	Location	Causes of Major Price Changes from Previous Year
2007/08	*RTO* -	Price of $41/MW-d is far below Net CONE, reflecting a capacity surplus.
	EMAAC and SWMAAC -	Prices near $200/MW-day are above Net CONE, reflecting tight supply.
2008/09	*RTO* -	$71/MW-d increase caused by relaxed EMAAC transmission constraint, modest demand growth, and a steep supply curve.
	EMAAC -	$49/MW-d drop caused by 2,085 MW CETL increase.
2009/10	*MAAC+APS* -	LDA is first modeled with prices $89/MW-d above the RTO. If MAAC had been modeled in earlier years, it likely would have had similarly high or higher prices.
	SWMAAC -	Clears a shade below the LDA price cap due to short supply and a steep supply curve.
2010/11	*RTO* -	Modest increases in demand, coupled with somewhat smaller increases in supply and steep supply curve cause RTO prices to increase by $72/MW-d.
	SWMAAC -	63/MW-d drop to the parent LDA price caused by lower offer prices for several existing generation supplies relative to 2009/10 offers, nearly 300 MW in generation uprates, a 276 MW increase in CETL, and a 29% reduction in SWMAAC Net CONE which reduced the VRR curve.
2011/12	*RTO* -	Exclusion of Duquesne load for one year causes some price suppression.
	LDAs -	No LDAs are modeled, preventing price separation.
2012/13	*RTO and LDAs* -	Large 8,200 MW influx of previously unoffered demand response is incorporated into the BRA due to a rule change in treatment from ILR to DR; this and a peak load forecast reduction cause a large $94/MW-d price drop in the RTO.
	LDAs -	Rule change permanently causes more LDAs to be modeled, allowing price separation.
2013/14	*LDAs* -	Large CETL reductions of almost 2,000 MW in MAAC and EMAAC and 675 MW in SWMAAC substantially restrict low-cost imports to the LDAs. Prices increase by $93/MW-d in MAAC and SWMAAC and by $205/MW-d in EMAAC.
2014/15	*RTO* -	Prices increase by $98/MW-d due primarily to high bids and excused capacity from coal units related to EPA HAP MACT regulations. More than 6,200 MW less existing generation clears in the unconstrained RTO (excluding ATSI, DEOK, and imports), replaced by a large increase in cleared demand resources.
	LDAs -	2.8% load forecast drop and 1,100 to 1,200 MW increase in CETL in MAAC, EMAAC, and SWMAAC create a supply surplus relative to previous year in eastern LDAs.
	PS-North -	Price drop of $31/MW-d is not as substantial as in other LDAs, and is limited by transmission constraints, which are near their historic levels.
	Extended Summer and Annual -	Resource types are modeled separately for the first time, leading to a $11/MW-d price premium for extended summer and annual resources in LDAs and a smaller premium less than $1/MW-d in the unconstrained RTO.

II. Summary of Market Results – Base Residual Auction Results

BRA Supply Curves (w/o Territory Expansions)



Incremental Auction Prices

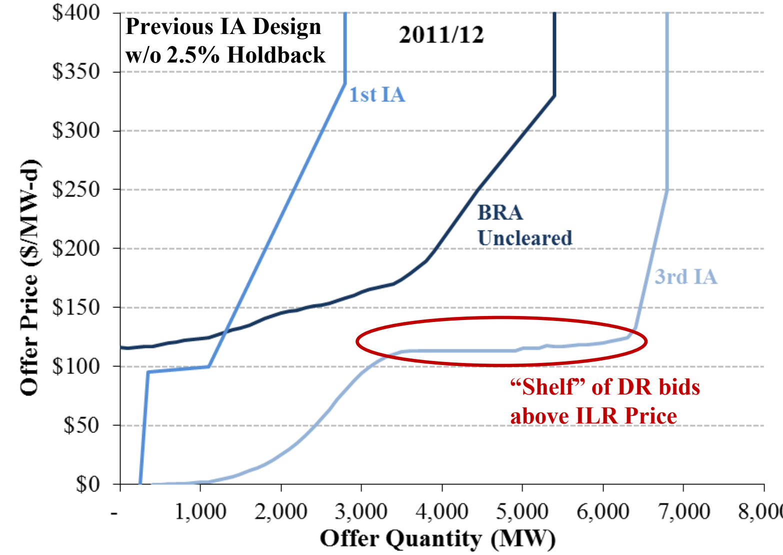


IA prices consistently far below BRA prices prior to IA re-design

Incremental Auction Supply Curves

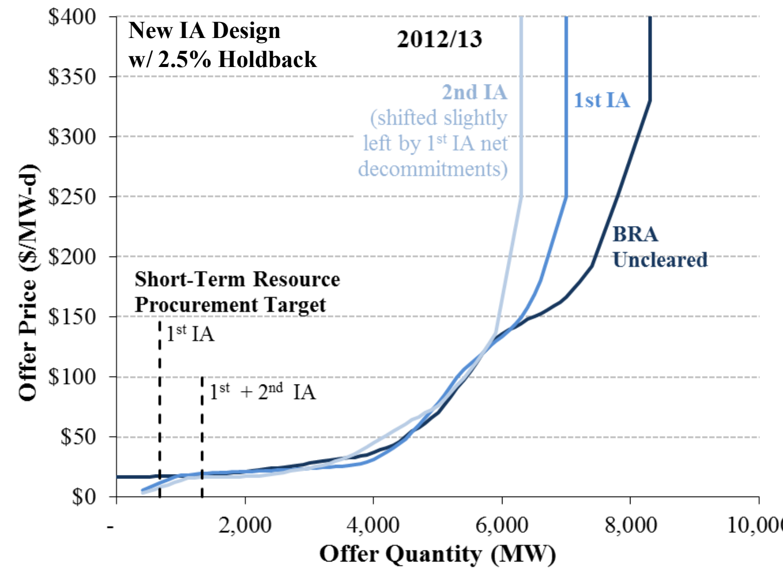
Previous IA Design

- Under the previous design, IA prices were persistently below BRA prices
  - Primarily related to offers from existing generation and uprates (with substantial offers near zero in the IAs)
  - Steep IA supply curves; but low prices given very low demand at prices appreciably above zero
- Problematic incentive: DR bids just above the BRA price in the 3rd IA (ILR could receive BRA-based price without clearing)



New IA Design

- Still limited experience under the revised IA design but results from the first two incremental auctions are promising
- Supply curves much more consistent with uncleared BRA supply
- Price differences between BRA and IAs are explained by changes to CETL and load forecast
- Insufficient evidence to date to consider revising short-term procurement in each IA (portion of 2.5%)



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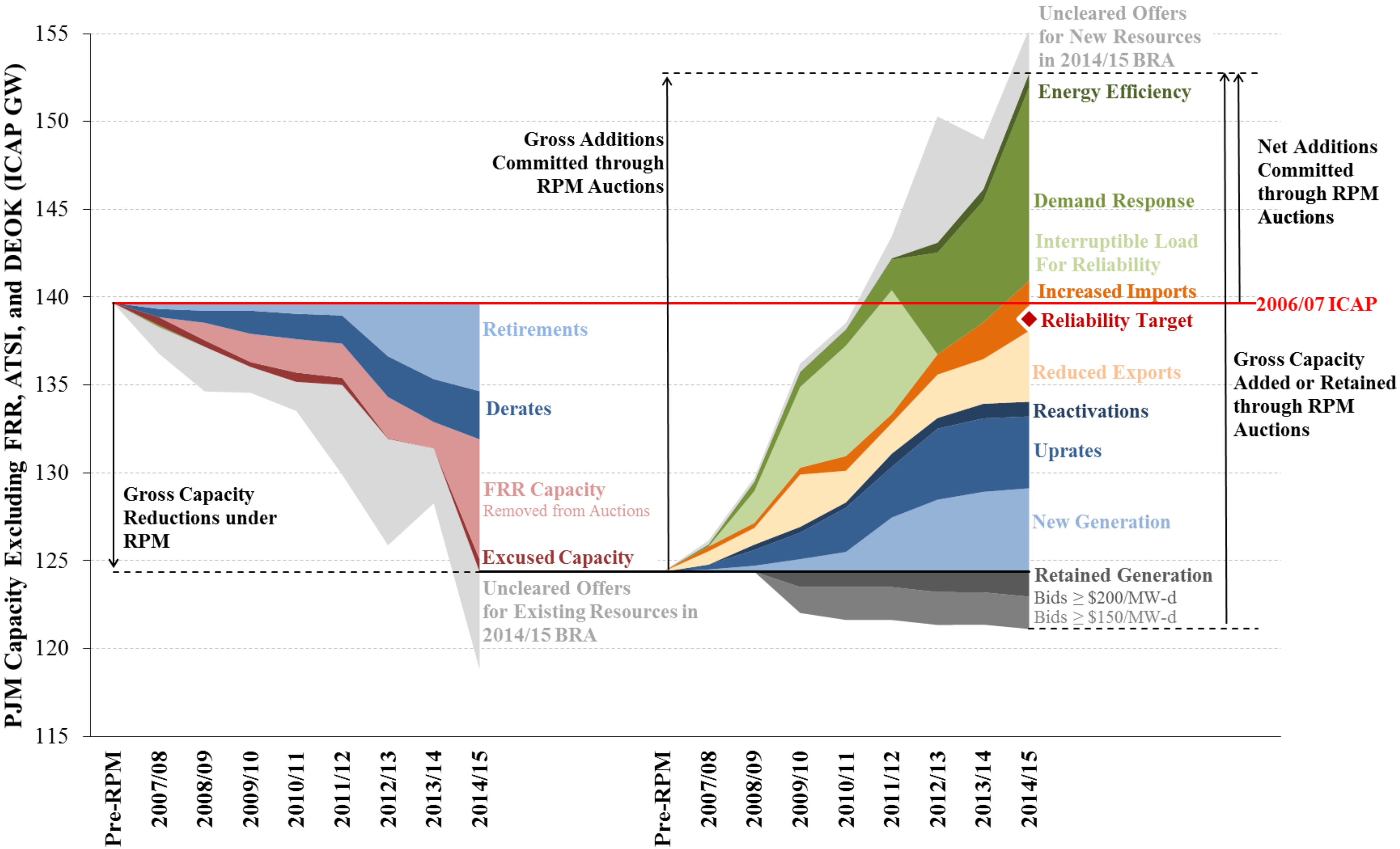
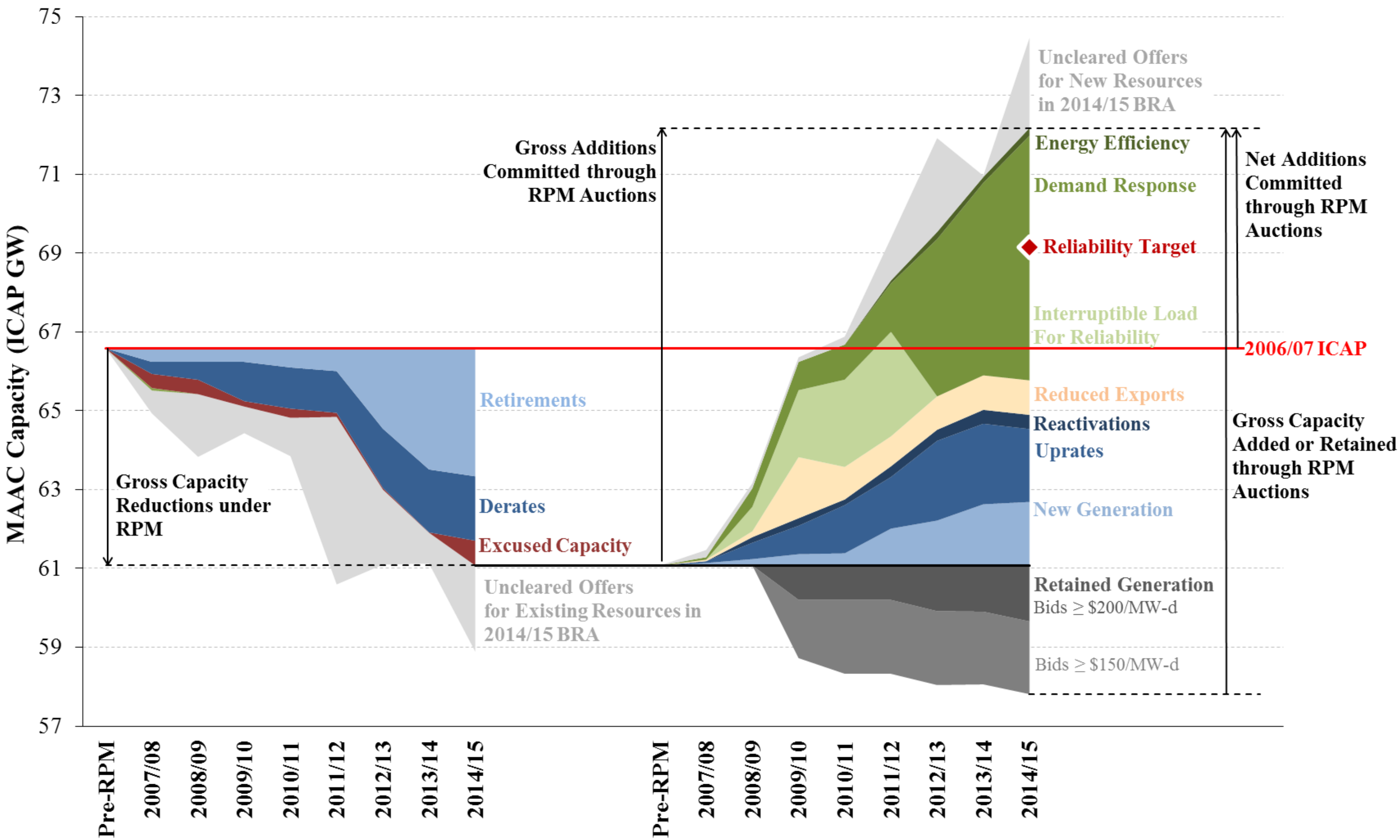
II. Summary of Market Results – Addition, Retention, and Retirements

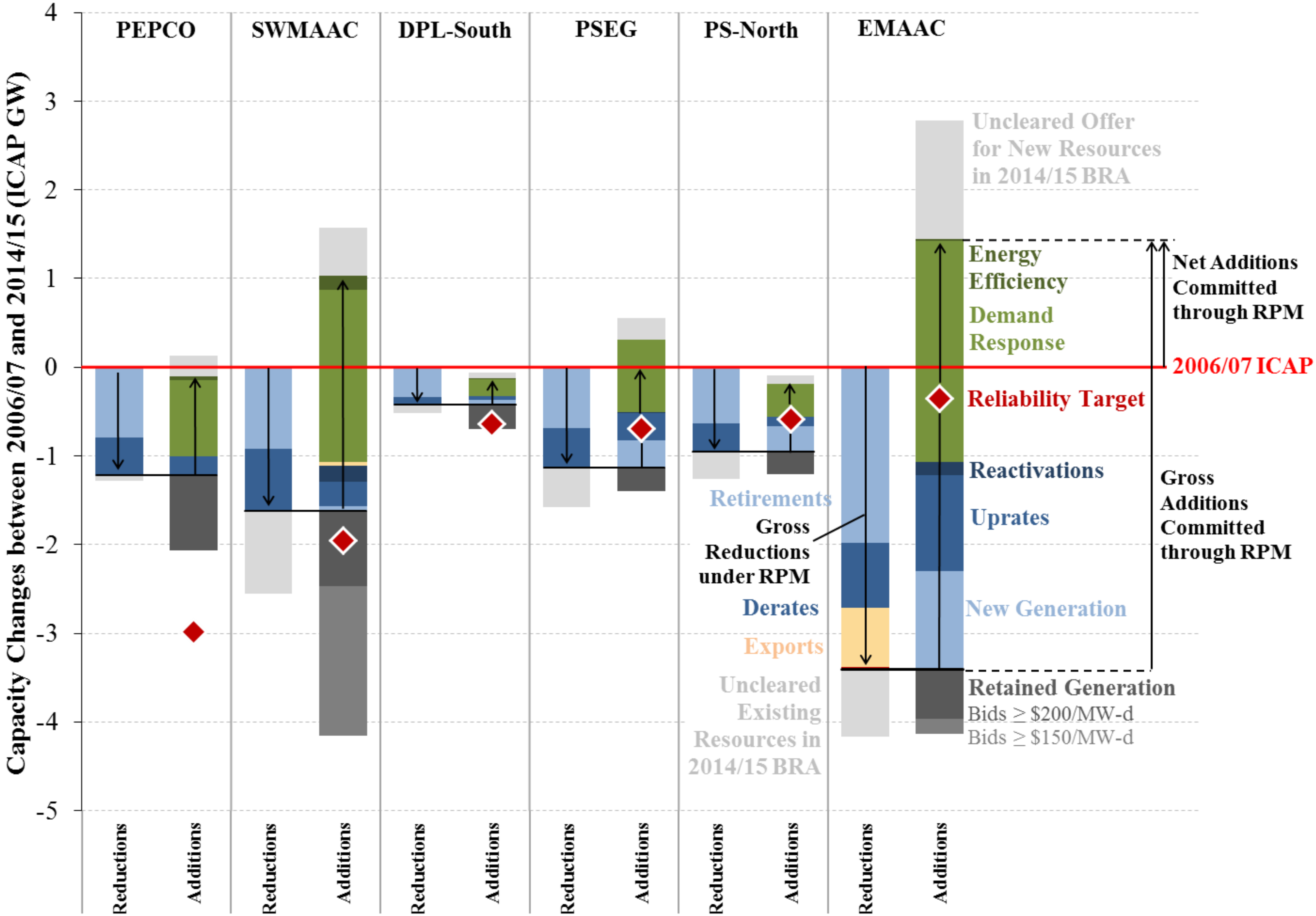
PJM Net Additions Cleared in RPM Auctions



MAAC Net Additions Cleared in RPM Auctions



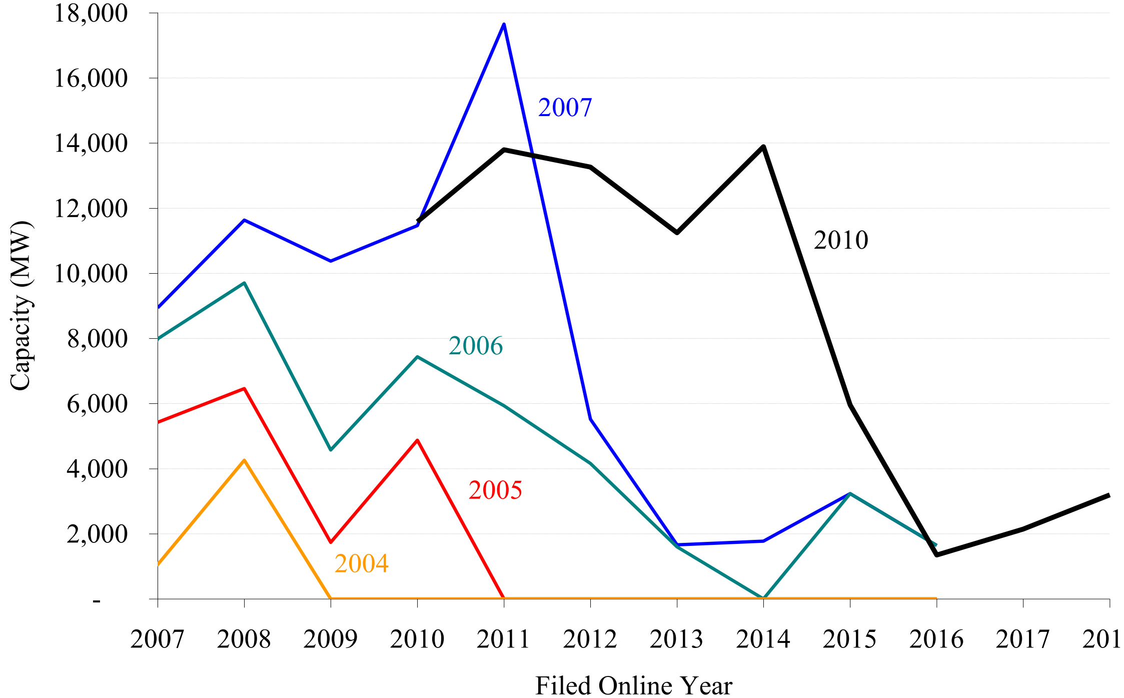
LDA Capacity Reductions and Additions



Generation Interconnection Queue

- Our 2008 RPM review documented significantly increased volumes of generation interconnection requests since RPM was implemented, but noted significant uncertainties and delays
- RPM-qualified generation capacity in the interconnection queue has remained high compared to needs:
  - 26,000 MW RTO wide
  - 13,000 MW in MAAC (3,100 MW in SWMAAC, 1,400 MW in PEPCO)
  - 7,300 MW in EMAAC (1,900 MW in PSEG, 500 MW in DPL)

Capacity of Active Generation Projects in Interconnection Queue by Stated Online Date



Source: 2005-2007, 2010 PJM State of the Market Reports.

- While considerable uncertainties remain (and may be unavoidable), PJM has implemented a number of changes to streamline the interconnection process, significantly improving on-time completion of interconnection studies:
  - Feasibility studies improved from 53% and 70% on time in 2007-08 to 89% on time in 2010
  - Impact studies improved from 44% and 29% on time in 2007-08 to 77% on time in 2010

Findings: Substantial Capacity Additions

Sufficient Capacity for Reliability

- RTO had surplus capacity procured in all years, partly related to pre-RPM surplus
- Some LDAs were deficient in early years (related to pre-RPM tight supply conditions), but every LDA has procured at least a small surplus over 2011/12 – 2014/15
- 2014/15 BRA resulted in surplus in every LDA, ensuring reliability despite the EPA HAP regulation which will require many environmental upgrades to coal units in that year

Additional Uncleared Capacity Available

- Every LDA has had substantial offers for additional capacity (including new generation) that did not clear but could have been procured at higher prices had it been needed for reliability
- One potential concern in PEPCO, where little new generation was offered, but resource adequacy has been maintained by new DR and uprates

Substantial Capacity Added (numbers exclude FRR and expansions)

- 28.4 GW of gross committed and 13.1 GW of net committed capacity has been added in PJM
- Of gross committed additions, 11.8 GW (ICAP) are increases in demand-side resources, 6.9 GW are increases in net imports, 4.8 GW are from new generation, 4.1 GW are from uprates, and 0.8 GW are from reactivations
- These additions were offset by 5.0 GW of retirements and 2.7 GW of derates, 6.8 GW removed from auctions for FRR, and 0.7 GW otherwise excused from auctions

Findings: Prices Consistent with Fundamentals

Prices Consistent with Market Fundamentals

- Prices mostly below Net CONE because new generation was not needed to maintain resource adequacy
- Prices above Net CONE in early years reflected tight supply conditions
- Locational price differentials reflect locational differences in capacity supply, including the impacts of transmission constraints

Costs Reduced by Competition

- RPM has created a level playing field for competition among capacity resource types, attracting new generation, DR, and uprates at prices less than Net CONE
- RPM has facilitated decisions by owners of coal plants whether to invest in environmental retrofits or retire and be replaced by more economic entrants, particularly in the 2014/15 BRA, when total cleared generation decreased by 7.7 UCAP GW while cleared DR increased by 5.0 UCAP GW relative to 2013/14 levels

Prices Have Been Volatile

- BRA prices changes have been considerable, but reflect changes in market fundamentals, auction rules, and parameters
- The BRA supply curves have become “flatter” over time, with more forward supply and DR resources, which will dampen price volatility going forward

Findings: Incremental Auctions / Queue

Incremental Auctions

- Clearing prices under the previous IA design did not track market fundamentals and were persistently far below BRA clearing prices
- There is insufficient experience with the new design to understand how it will function over time, but initial results after the first two IAs are promising:
  - IA supply curves were much closer to the uncleared portion of the BRA supply curve
  - Market price differentials between the BRA and IAs are explained by changes to CETL and peak load forecast

Generation Interconnection Queue

- A significant amount of generation projects from PJM's generation interconnection queue qualify for RPM participation with 3-year forward in-service date
- PJM has undertaken significant queue improvements and has increased proportion of on-time interconnection studies
- PJM should continue its ongoing effort to improve the generation interconnection process

Contents

Process for Gathering Stakeholder Input

Sector Interviews

- Conducted group interviews with Transmission Owners, Generation Owners, Electric Distributors, End-Use Customers, and Other Suppliers
- Received 13 sets of written comments plus some follow-up interviews with individual stakeholders

Financial Analysts

- Interviewed financial analysts from CitiGroup, UBS, and Goldman Sachs

Monitoring Analytics

- We had two meetings and other correspondence with the IMM

State Commissions

- Individual calls with state commissions in DE, NJ, OH, and DC
- Individual calls with commission staff from NC, and PA
- Written comments from MI, and VA
- MD and KY declined to participate; WV, TN, IL, and IN did not respond

Key Themes

Stakeholders identified a number of issues concerns that we used to guide our performance assessment

- Our report summarizes these comments by sector
- Key areas of concern that emerged are:
  1. Price volatility and unpredictability
  2. The capability of RPM to attract new generation investments, and the lack of PPAs to support new plant financing
  3. Equal compensation for new and old generation
  4. The risk of large simultaneous environmental retirements
  5. The dependability of demand resources
  6. RPM target procurement
- Our report provides a general response to these concerns, including an explanation of how we have analyzed the issues

1. Price Volatility and Uncertainty

In response to substantial stakeholder concerns, we documented and analyzed 3 drivers of major price changes and uncertainty under RPM

- ***Market Fundamentals*** - Impacts of DR growth, economic downturn, and need for transmission and environmental upgrades should not be dampened by an overly flat VRR curve or other administrative means
- ***Previous Design Changes*** – Past price changes from RPM design improvements are not an issue going forward:
  - Accounting for DR supply outside RPM auctions rather than within auctions
  - Not modeling major LDAs
- ***Current Design*** – Some design elements and administrative parameters are causing excess risk
  - Volatility and uncertainty in administrative CETL, load forecast, and locational reliability requirement calculations
  - Potentially not modeling LDAs that may be capacity constrained in the future

We focus primarily on reducing price volatility caused by current design elements

2. Lack of Long-Term Contracts to Support New Plants

Number of interrelated concerns:

- Some generators and lenders point out that long-term contracts are unavailable, but needed to support plant development through project financing
- Some generators and regulators point to the lack of new construction
- Some LSEs (public power) would like to sign long-term contracts but note that suppliers are unwilling to offer them

Lack of need for new capacity largely explains observations:

- Excess capacity and low prices in most of PJM (through 2014-15)
- Higher prices (but below the cost of new plants) in Eastern PJM have ensured sufficient capacity through DR, upgrades, and retention of existing capacity
- Transmission upgrades will reduce prices in Eastern PJM (e.g., in 2014-15)
- Under these conditions, caused in part by economic downturn, above-market PPAs are the only way to develop and obtain financing for (unneeded) new plants
- Suppliers of existing capacity are unwilling to lock in low current prices through long-term contracts, while buyers are unwilling to pay for cost of new capacity

2. Lack of Long-Term Contracts to Support New Plants

The role and effect of "project finance"

- Large companies can finance power plants with their own equity and debt (balance sheet financing):
  - Predominant model in many capital intensive industries (e.g., oil and gas exploration)
  - Balance sheet financing also used by some larger renewables developers
- Project developers with poor credit or without their own funds need to rely on project-specific "non-recourse" debt (project finance) and third-party equity
  - Because of higher risks, non-recourse debt is more expensive than corporate debt (though still cheaper than equity)
  - Developers can reduce "revenue requirements" below merchant costs through long-term PPAs that remove market risks and allow high leverage (e.g., 80% debt)
  - Risk transfer through long-term PPAs reduces contract price but not total cost

Incentives of developers and lenders

- Developers seek PPAs to "save" projects that have been in the development pipeline but are no longer needed due to changes in market fundamentals
- Lenders will see PPAs as solution to stalled business prospects

2. Lack of Long-Term Contracts to Support New Plants

Structure of "default service" in eastern PJM's retail access states likely contributes to the lack of long-term contracting, possibly making new investment more difficult

- In retail access states, much of total load is on regulated "default service"
  - Competitive retail providers may have a portfolio of physical assets and supply contracts of various durations, but default service is procured entirely with shorter-term contracts (1-3 years)
  - While competitive retail providers are willing to make long-term commitments (e.g., through the purchase of generation assets), the provision of default service does not currently allow for such commitments
- If needed, best solution may be for states to revise default service rules, possibly adding non-discriminatory long-term procurement of a portion of needs
  - Note, however, that most end users don't sign long-term contracts for energy (e.g., gasoline, heating oil). Similarly, large industrial or commercial customers generally are unwilling to sign long-term fixed-priced contracts
- Future resource adequacy need, customer load uncertainty, and default service design could eventually make non-discriminatory long-term procurement through RPM a necessary 2nd-best option. For now, start with voluntary long-term auctions.

3. Equal Compensation for Old and New Generation

Several state commissions expressed concern that old generating plants with high emissions receive the same compensation as new generation under RPM

- Environmental issues
  - RPM is well-designed to internalize the fixed and variable costs of complying with environmental regulations
  - RPM should not be expected to impose tighter environmental standards than state and federal governments have currently defined
- Price discrimination
  - Restructured-market prices do not follow the trajectory of regulated markets in which cost recovery begins above the "levelized" level and declines as the plant depreciates
  - Trying to differentiate payments based on age would be inconsistent with a construct in which all resources are selling the same capacity product
  - Would lead to inefficiency and higher costs in the long-term

4. Vulnerability to Environmental Retirements

Several stakeholders expressed concern about RPM's ability to replace or prevent excessive retirements caused by EPA's new HAP MACT and other regulations

- We find that RPM is well designed to procure enough capacity to meet resource adequacy targets, due to its retrofit provisions, the forward period, and centralized clearing
- So far, RPM has successfully and economically supported resource adequacy, including in the 2014/15 auction covering the first 5 months of EPA's HAP MACT regulations
- However, RPM has not been tested with larger amounts of simultaneous retirements in LDAs. Thus, too early to tell how well RPM (or any other construct) will mitigate retirement threats caused by the full slate of new regulations planned to take effect between 2015 and 2018
- Given the risks, we recommend that PJM implement several safeguards and continue to monitor auction outcomes and potential retirements

5. The Dependability of Demand Resources

Generation owners expressed concern that DR accounted for 9.4% of cleared resources in the 2014/15 BRA without assurance that so much DR can be developed and perform

- We do not share that concern at this point:
  - Committed DR capacity is 4.0 GW (UCAP) more than the 10.9 GW of ILR, DR, and EE already registered for the current 2011/12 delivery year (which has been performing well during recent heat wave), compared to a 6.0 GW (UCAP) increase over the past three years
  - Exchanges of DR commitments in incremental auctions similar to generation
  - RPM verification and penalty provisions will enforce suppliers' commitments (penalty provisions for deficiencies and performance violations roughly comparable to those of generation)
- However, we recommend refinements to the resource verification process to improve RPM efficiency and ensure that resources can perform as frequently as claimed: introduce audits of contracts for ability to respond as frequently and seasonally as claimed

6. RPM Procurement Targets

Stakeholders raised concerns about whether the reliability requirements for the RTO and LDAs are at the right level

- We recognize that reviewing reliability targets is not within the scope of our evaluation of RPM's performance in meeting already-defined resource adequacy objectives
- However, in response to stakeholder concerns we recommend further examining reliability targets and improving the load forecasting process:
  - 1-in-25: review the standard and its invariance with LDA import level
  - 1-in-10: document the tradeoffs between reliability targets, the cost of new capacity, and the economic value of resulting reserve margins
  - Increase transparency of load forecasting and uncertainty range
  - Coordinate with RTEP process

Contents

Gross CONE Estimate

Scope and Approach

- *Scope*: provided CC and CT capital cost estimates for each of five CONE areas
- *Reference Resource Specifications*: used “revealed preferences” and other analysis of costs and locational characteristics to identify dominant technologies and designs
- *Plant Capital Cost Estimate*: EPC contractor CH2M HILL developed detailed plant capital cost estimates for reference resources using the same estimation techniques they use to bid actual projects; Brattle developed cost estimates the components of owners costs not provided by CH2M HILL (e.g., development costs, land, gas and electric interconnection, contingency)
- *Fixed Operations and Maintenance Costs*: Wood Group estimated locational FOM costs; Brattle developed cost estimates for other fixed costs (e.g., property taxes and insurance)
- *Cost Levelization*: calculated level-real and level-nominal costs for merchant generators assuming balance-sheet financing without power purchase agreements; examined the rationale for level-real vs. level-nominal

Plant Siting Location

Siting Criteria for Selecting Locations

- Major gas pipeline and high voltage transmission
- Recently-built or under-construction CCs and CTs; most new units are in infrastructure corridors (see right)
- Availability of vacant industrial land

Gas CTs Built Since 2002

Gas CCs Built Since 2002

Maryland Siting Difficulty

- SWMAAC siting assumptions less straightforward as no recently built or under construction gas units exist
- Relied on above criteria, a 640 MW permitted CC project, and a 1996 230 MW gas cogen addition in a neighboring county

CONE Area	Sited Plant Location		Interconnection	Gas Pipeline Infrastructure Available
	County	*Zone*	*(kV)*	
1 Eastern MAAC	Middlesex, NJ	JCPL	230	Transco, Texas Eastern
2 Southwest MAAC	Charles, MD	PEPCO	230	Dominion Cove Point
3 Rest of RTO	Will, IL	COMED	345	ANR, NGPL, Midwestern, Guardian/Vector
4 Western MAAC	Northampton, PA	PPL	230	Transco, Columbia
5 Dominion	Fauquier, VA	DOM	230	Transco, Columbia, Dominion

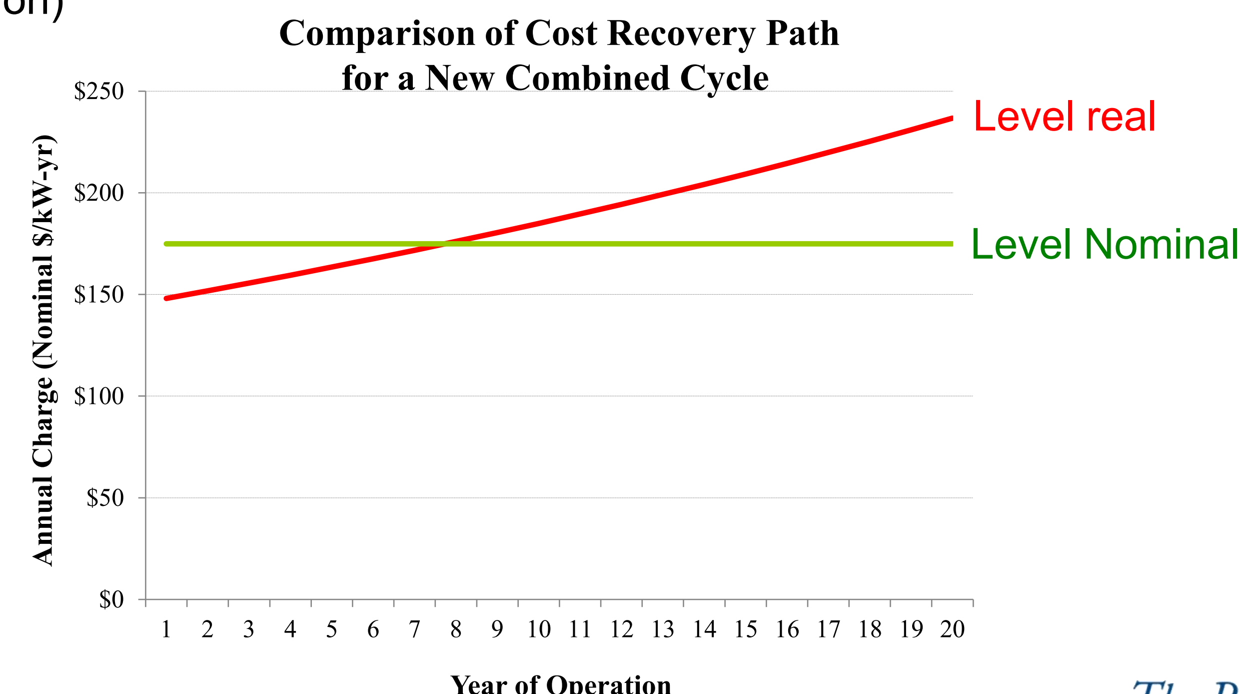
Reference Technology Specifications

Plant Characteristic	Simple Cycle	Combined Cycle
Turbine Model	GE 7FA.05	GE 7FA.05
Configuration	2 x 0	2 x 1
Net Plant Power Rating	CONE Areas 1-4 (w/ SCR): 418 MW at 59 °F 390 MW at 92 °F CONE Area 5 (w/o SCR): 420 MW at 59 °F 392 MW at 92 °F	Baseload (w/o Duct Firing): 627 MW at 59 °F 584 MW at 92 °F Maximum Load (w/ Duct Firing): 701 MW at 59 °F 656 MW at 92 °F
Cooling System	n/a	Cooling Tower
Power Augmentation	Evaporative Cooling	Evaporative Cooling
Net Heat Rate (HHV)	CONE Areas 1-4 (w/ SCR): 10,094 btu/kWh at 59 °F 10,320 btu/kWh at 92 °F CONE Area 5 (w/o SCR): 10,036 btu/kWh at 59 °F 10,257 btu/kWh at 92 °F	Baseload (w/o Duct Firing): 6,722 btu/kWh 59 °F 6,883 btu/kWh 92 °F Maximum Load (w/ Duct Firing): 6,914 btu/kWh at 59 °F 7,096 btu/kWh at 92 °F
NO_X Controls	Dry Low NO_X Burners Selective Catalytic Reduction (Areas 1-4) Water Injection for DFO (Areas 1-2, 4-5)	Dry Low NO_X Burners Selective Catalytic Reduction Water Injection for DFO (Areas 1-2, 4-5)
Dual Fuel Capability	Single Fuel (Area 3) Distillate Fuel Oil (Areas 1-2, 4-5)	Single Fuel (Area 3) Distillate Fuel Oil (Areas 1-2, 4-5)
Blackstart Capability	None	None
On-Site Gas Compression	None	None

Levelization Approach

Translating investment costs into annualized costs requires assumption about how received payments change over time. Three major "levelization" approaches are available for this purpose:

1. Level Nominal: annual payments remain constant over time (in nominal terms)
2. Level Real: annual payments increase with general inflation over time (i.e., remain constant in real dollar terms)
3. Levelization based on technology-specific payment trajectory (e.g., based on forecast of CT-cost inflation)



Levelization Approach

We recommend transitioning to CONE based on level-real:

- CONE based on “level nominal” will overcompensate resources as CONE values are increased with CT cost trends over time:
  - Compensative amount in first year, but more in following years as capacity payments increase with CT costs
- “Level real” may under- or overcompensate resources:
  - Undercompensate if (1) CT costs increase by less than inflation; or (2) CT costs increase with inflation but there is E&AS revenue erosion relative to new CTs.
  - Overcompensate if CT costs (net of E&AS revenue erosion) increase faster than inflation
- Average CT costs have increased at or above inflation rates
  - CT cost trends (H-W for turbo generators) matched CPI inflation over last 50 years
  - Exceeded inflation by 60-80 bpts over last 20 years (and by 130-150 bpts over the last 10 years)
  - Environmental requirements and overseas growth may keep CT cost trends above inflation
- E&AS erosion only modest for CTs:
  - Declining heat rates (steady improvements of 100 per year over last 20 years)
  - But modest impact on CT revenues (worth approx. $5/kW-yr over 20 years)
  - Equivalent to fixed-cost recovery growing at 0.5% (50 bpts) less than CONE increases
- Likely positive terminal value at end of 20-year levelization period

However, level-real should be used *only* if related recommendations (higher cap on the VRR curve and calibrated or forward-looking E&AS offsets) are implemented

Cost of Capital Estimate

- Cost of capital estimate (and long-term inflation forecast of 2.5%) based on May 2011 market data

Merchant Generation Company	S&P Credit Rating	Brattle Estimates: Cost of Equity (%)	Cost of Debt (%)	Debt-to-Equity Ratio	ATWACC (%)	Analyst ATWACC Estimates (%)
	[1]	[2]	[3]	[4]	[5]	[6]
Comparable Merchant Power Generation Companies						
NRG Energy Inc	BB	11.4%	7.0%	59/41	7.2%	7.1%
Genon Energy Inc (fka RRI Energy)	B	15.6%	8.5%	41/59	11.2%	8.5% - 9.5%
Calpine Corp	B	12.7%	8.5%	67/33	7.6%	7.5%
Genon Energy Holdings Inc (fka Mirant)	B	11.3%	8.5%	38/62	8.9%	8.5% - 9.5%
Dynegy Inc	B	14.4%	8.5%	66/34	8.3%	8.0% - 12.0%
Merchant Generation Segments of Publicly Traded Companies						
FirstEnergy Merchant Generation						8.0% - 9.0%
Allegheny Merchant Generation						8.0% - 8.5%
Duke's Merchant Generation						8.2% - 9.2%
Average					**8.6%**	
Median					**8.3%**	
Value-weighted Portfolio Average		12.3%	8.0%	56.2%	**8.1%**	
Brattle Recommended Financial Parameters		**12.5%**	**7.5%**	**50.0%**	**8.5%**	

CONE Study Summary of Results

Combustion Turbine (Simple-Cycle) CONE

CONE Area	*Brattle* Estimate		2014/15 CT CONE
	Level Real (2015$/kW-y)	Level Nominal (2015$/kW-y)	Escalated at CPI for 1 Year (2015$/kW-y)
1 Eastern MAAC	$111.9	$133.9	$142.1
2 Southwest MAAC	$103.3	$123.6	$131.4
3 Rest of RTO	$103.1	$123.4	$135.0
4 Western MAAC	$108.6	$130.0	$131.4
5 Dominion	$92.8	$111.0	$131.5

Combined-Cycle CONE

CONE Area	*Brattle* Estimate		2014/15 CC CONE
	Level Real (2015$/kW-y)	Level Nominal (2015$/kW-y)	Escalated at CPI for 1 Year (2015$/kW-y)
1 Eastern MAAC	$140.5	$168.1	$179.6
2 Southwest MAAC	$123.3	$147.5	$158.7
3 Rest of RTO	$135.5	$162.1	$168.5
4 Western MAAC	$135.1	$161.8	$158.7
5 Dominion	$120.2	$143.8	$158.7

Gas CT CONE Detail

Cone Area	Total Plant Capital Cost ($M)	Net Summer ICAP (MW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-y)	After-Tax WACC (%)	Levelized Gross CONE Level Real ($/kW-y)	Levelized Gross CONE Level Nominal ($/kW-y)
Brattle 2011 Estimate							
June 1, 2015 Online Date (2015$)							
1 Eastern MAAC	$308.0	390	$790.5	$15.7	8.47%	$111.9	$133.9
2 Southwest MAAC	$281.2	390	$721.8	$15.8	8.49%	$103.3	$123.6
3 Rest of RTO	$287.1	390	$736.8	$15.2	8.46%	$103.1	$123.4
4 Western MAAC	$299.1	390	$767.7	$15.1	8.44%	$108.6	$130.0
5 Dominion	$254.7	392	$649.7	$14.7	8.54%	$92.8	$111.0
Power Project Management, LLC 2008 Update							
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)							
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%	n/a	$154.4
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%	n/a	$142.8
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%	n/a	$146.1

Notes:

Dominion estimate assumes no SCR. With SCR, CONE increases to $100.8/kW-y and $120.6/kW-y for level-real and level-nominal, respectively.
Rest of RTO estimate assumes single fuel. With dual fuel, CONE increases to $110.6/kW-y and $132.4/kW-y for level-real and level-nominal, respectively.
PPM's estimates shown here were subsequently discounted 10% in settlement, then escalated at Handy-Whitman Index for setting Net CONE.

Gas CC CONE Detail

Cone Area	Total Plant Capital Cost ($M)	Net Summer ICAP (MW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-y)	After-Tax WACC (%)	Levelized Gross CONE	
						Level Real ($/kW-y)	Level Nominal ($/kW-y)
Brattle 2011 Estimate							
June 1, 2015 Online Date (2015$)							
1 Eastern MAAC	$621.2	656	$947.5	$16.7	8.47%	$140.5	$168.1
2 Southwest MAAC	$537.2	656	$819.3	$16.6	8.49%	$123.3	$147.5
3 Rest of RTO	$599.0	656	$913.5	$16.0	8.46%	$135.5	$162.1
4 Western MAAC	$597.4	656	$911.1	$15.8	8.44%	$135.1	$161.8
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8
Pasteris 2011 Update							
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)							
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%	n/a	$179.6
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%	n/a	$158.7
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%	n/a	$168.5

Note:
Rest of RTO estimate assumes single fuel. With dual fuel, CONE increases to $138.9/kW-y and $166.3/kW-y for level-real and level-nominal, respectively.

Energy and Ancillary Service Offset Methodology

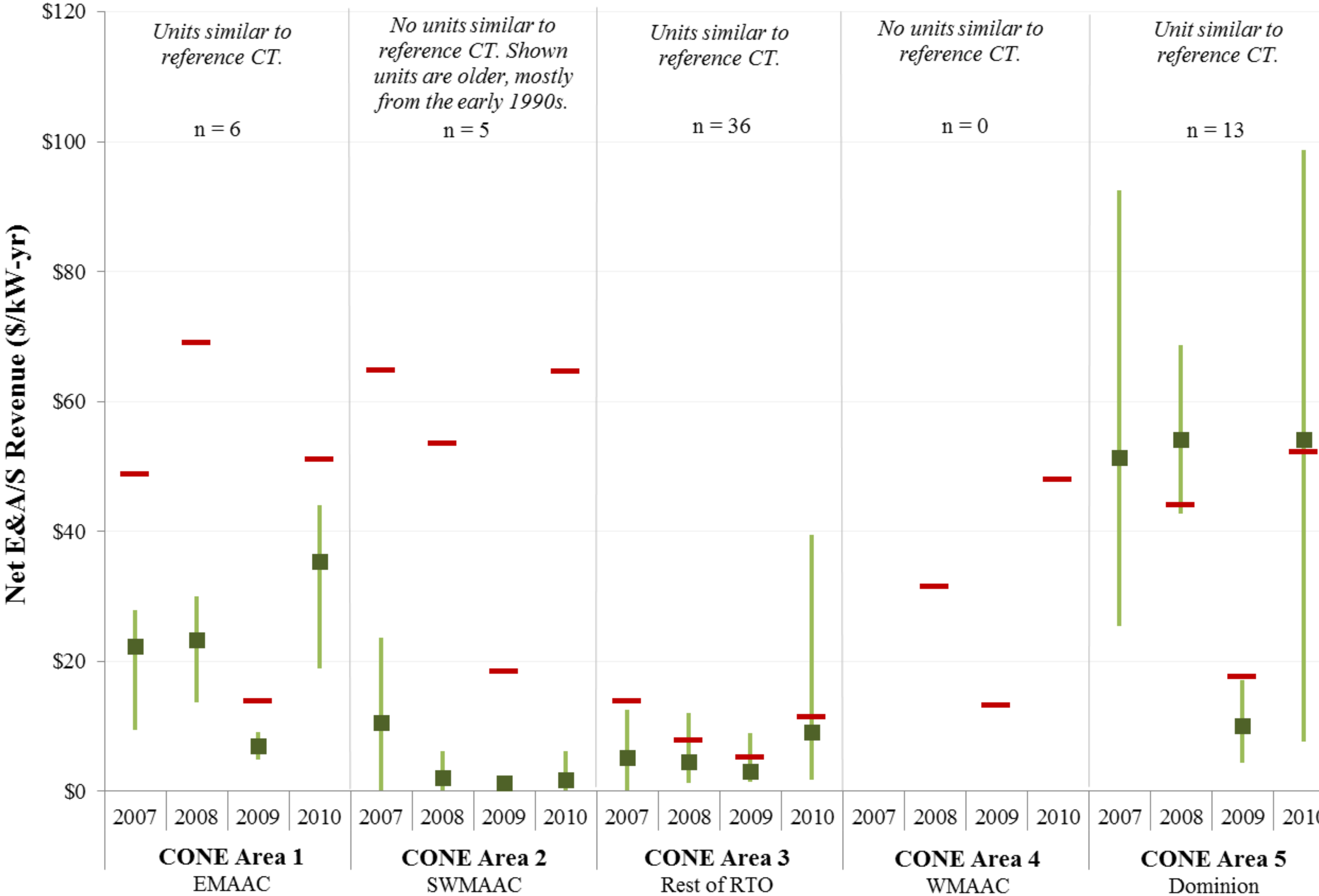
We address three key questions about the administrative E&AS offset methodology:

- How accurate is the administrative calculation of E&AS margins relative to what is actually earned by generators similar to the reference technology?
- Should the historically based offset be replaced by a forward-looking or equilibrium-based estimate?
- How should scarcity prices be accounted for in the E&AS offset?

In analyzing these questions we considered:

- Theoretical implications of potential approaches, and
- Practical challenges of implementation, including transparency

CT Offset Compared to Actual Margins

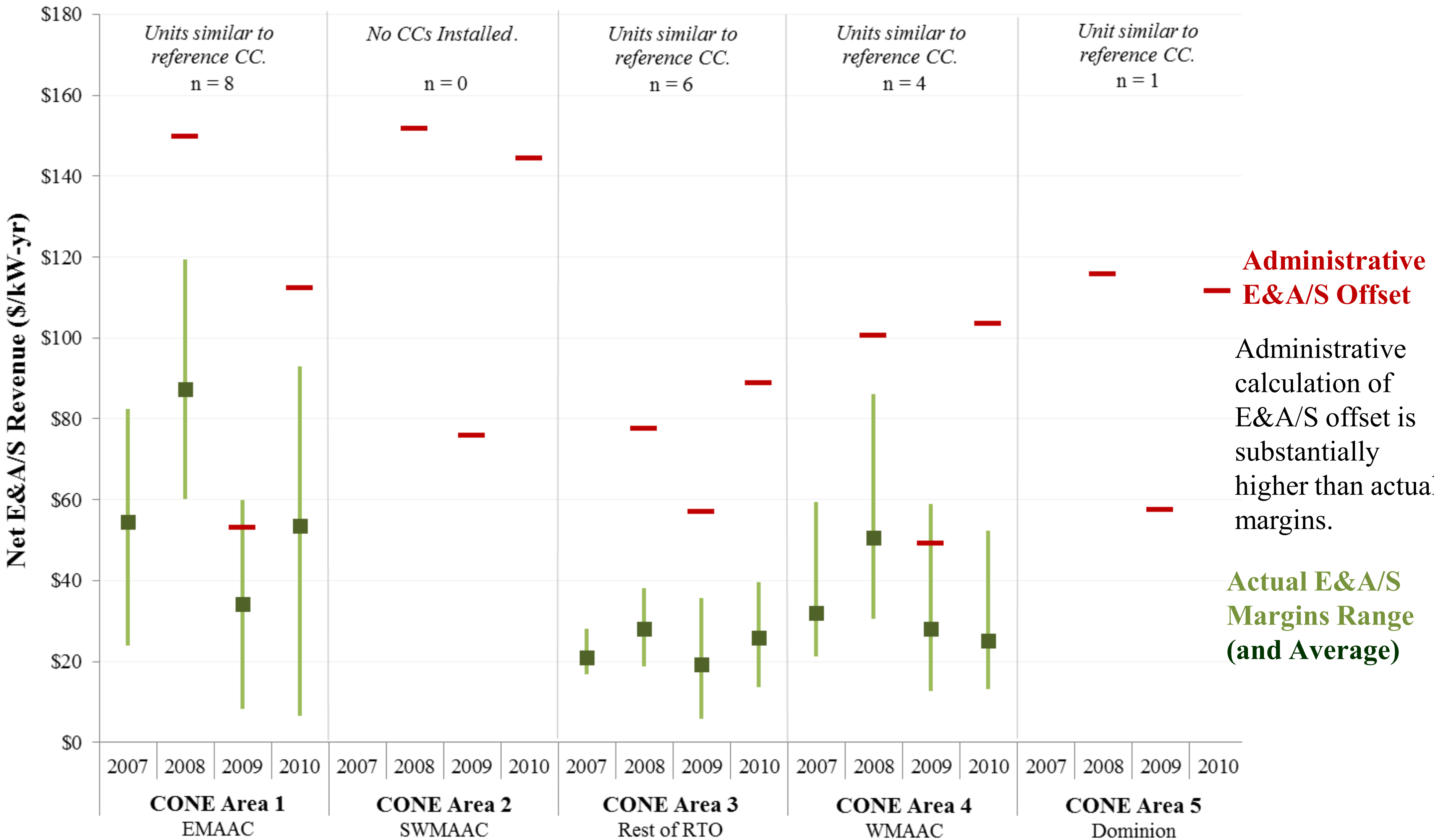


Administrative calculation for EMAAC (and possibly other LDAs) is substantially higher than actual units, due partly to use of Gross CONE zone.

Administrative E&A/S Offset

Actual E&A/S Margins Range (and Average)

CC Offset Compared to Actual Margins



Administrative calculation of E&A/S offset is substantially higher than actual margins.

Recommended Changes to Historical Calculation

Accuracy of E&AS Offset

- Administratively determined E&AS offset exceeds actual E&AS margins
  - Substantially higher than actual CC net revenues in all CONE Areas and substantially higher than actual CT revenues in EMAAC and SWMAAC
  - Large part of the discrepancy appears driven by:
    - Exclusive reliance on RT prices (as opposed to majority of revenues obtained in DA market, even for CTs)
    - Actual costs that exceed estimated costs (e.g., when running on fuel oil)
- We recommend calibrating the calculation of E&AS offsets to those actually realized by units similar to reference CT or CC, by either:
  - Calibrating calculation so it accurately reflects actual margins including potentially revising the approach to determining dispatch rules (RT vs. DA) and which zonal price to use; or
  - Calculating E&AS offset directly from representative units' historic margins (but avoid distortion by idiosyncratic factors affecting individual units)

Concerns Regarding Overall E&AS Approach

Current Backward-Looking E&AS Offset

- Biased by substantial (4-7 year) time lag in fuel costs, transmission, and other market fundamentals
- Leads distortions of price signals: high E&AS offset due to price spikes results in low capacity prices, thereby potentially undermining investments when needed most
- Significant added volatility due to E&AS impacts from unusual weather and outage patterns
- Can result in "collapse" of VRR curve and resource adequacy deficiency (see VRR curve discussion)

Forward-Looking, Normalized E&AS Offset

- Forward-looking E&AS would incorporate futures prices for future fuel and energy under normalized weather and outage conditions; possibly adjusted for transmission upgrades
- Results would be highly dependent on methodology

Equilibrium E&AS Offset

- An E&AS calculation consistent with equilibrium reserve margins would be theoretically superior, consistent with a VRR curve that would reflect a long-run equilibrium
- Difficult to develop a transparent approach and sensitive to modeling decisions

Scarcity Pricing

- Transition to scarcity pricing could result in a few years of low E&AS offsets
- Longer-term issues caused by increased volatility in year-to-year energy prices

Recommendations

Recommend re-initiation of efforts to develop a normalized forward-looking or equilibrium E&AS offset:

- Forward-looking fuel and emissions prices
- Normalized for unusual weather and outages
- Possibly based on equilibrium reserve margins (and equilibrium price distributions) to guide the market toward long run equilibrium
- Though we recognize that stakeholders have already considered developing a forward-looking E&AS methodology but could not identify a sufficiently transparent and reliable method.

If historic E&AS is retained:

- Calibrate E&AS offset calculation to correctly capture actual E&AS margins
- Increase cap of VRR curve, as discussed in the next section.

Determining CONE from Offers for New Generation

Available BRA offer data does not provide a sound basis for determining Net CONE empirically:

- Our review of all actual offers by new entrants shows range in offer prices that is too wide to guide Net CONE determinations
- Many non-gas resources, including renewable generation, have submitted offers at zero
- Gas-fired generation have submitted offers at a large range of prices, both substantially above and below Net CONE
- Individual units have offered sections of their capacity over a large range of prices

Offers seem to reflect a range of different bidding, hedging, and timing strategies that result in first-year bids that substantially deviate from levelized costs.

Contents

Overview of Analysis

Identified RPM performance risks with the current VRR curve

- As in our 2008 report, updated Hobbs simulations show performance risk when using historic E&AS
- Risks due to “collapse” of VRR Curve low when historic E&AS is very high
- Low cap of VRR curve has already suppressed procurement in some LDAs

Analyzed alternative approaches to mitigating risk

- Our 2008 report already identified risks with historic offset, recommending replacing it with a forward-looking offset (but unsuccessful stakeholder effort)
- We now developed alternatives that would improve the performance of the VRR Curve while still using historic E&AS offsets

Also evaluated VRR curve slope

- Analyzed impact of a vertical demand curve or a flatter VRR curve on RTO and LDA clearing prices during the last seven BRAs
- Analyzed whether flatter VRR curves applied to LDAs would be an effective tool to reduce capacity price volatility within LDAs

Performance of VRR Curve in Hobbs Simulations

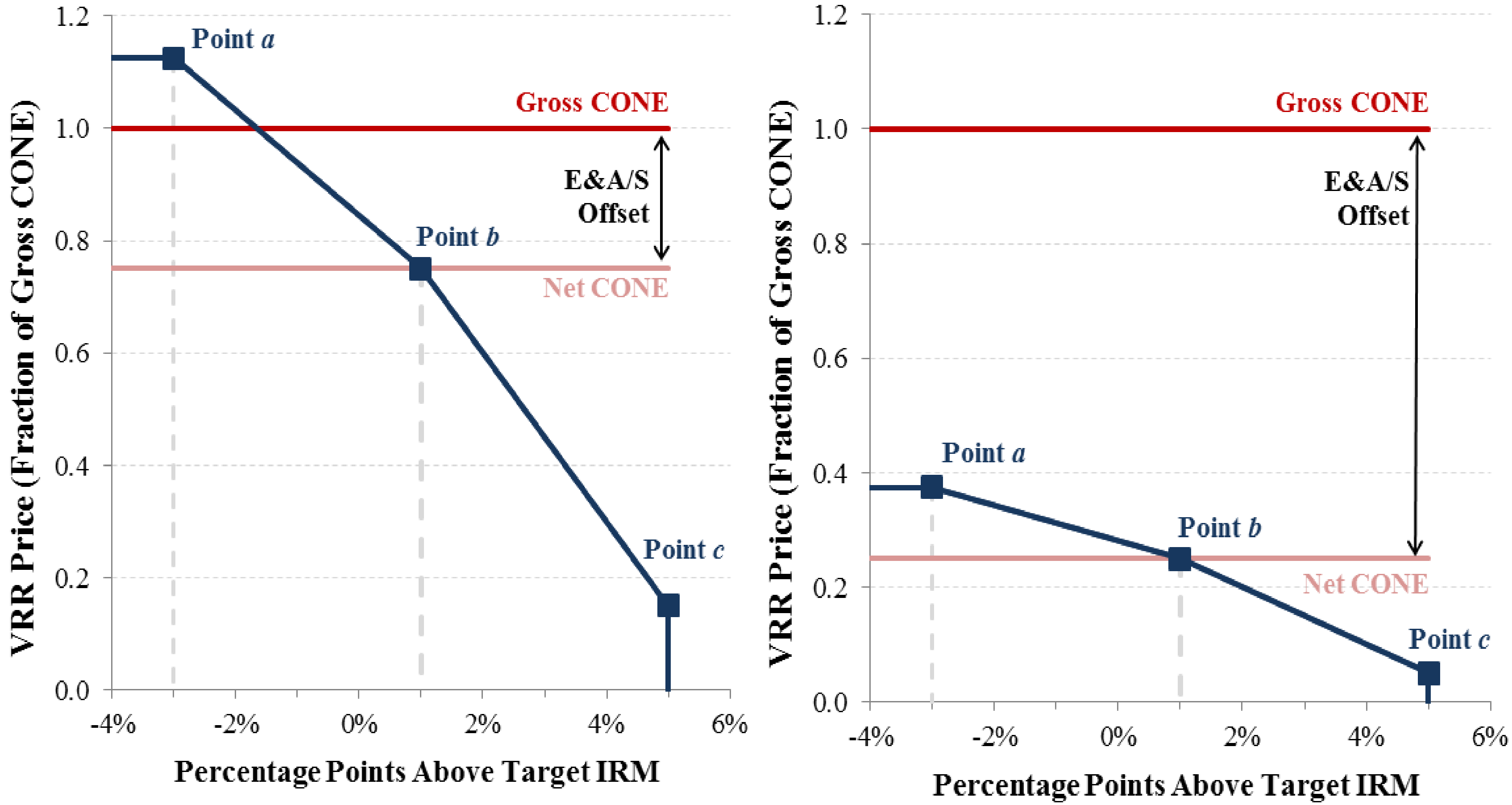
- Prof. Hobbs' original simulations were based on a constant E&AS offset
- Simulated RPM performance of the Settlement Curve plummets when the constant E&AS offset is replaced with a historic E&AS offset
  - Planning reserves for the delivery year exceed the reliability target during only 26% of all years (down from 86%)
  - Average actual reserve margins during the delivery years are more than 5% points <u>below</u> reliability target (down from 0.7% points <u>above</u> target)
  - Total consumer payments for capacity and E&AS margins increase to \$207/kW-yr (up from \$142/kW-yr) with a standard deviation of \$146/kW-yr (up from \$47/kW-yr)
- Consistent with our findings in our 2008 report, even after updates to various aspect of the model
- Additional analyses show that the primary reason for the poor performance of the Settlement Curve using historic E&AS offsets relates to how point "a" (the cap of the VRR curve) is defined…

Explanation of Performance Risk

- The cap of the VRR curve (point "a") can become too low when historic E&AS is high, leading to a low-reliability equilibrium
  - VRR curve is capped at point "a" 1.5xNetCONE
  - Because Net CONE declines as E&AS offsets increase, the VRR cap (point "a") will decline 1.5 times as fast
  - The higher the historic E&AS offset, the lower the VRR cap and flatter the slope of the VRR curve between points "a" and "b"
  - If historic E&AS offset ever reaches or exceeds gross CONE (e.g., due to unusual weather or outages), Net CONE, the VRR slope, and cap will all drop to zero
  - In that case, VRR curve no longer provides any incentive to add resources even if reserve margins are well below the reliability target
- Difference between point "a" and point "b" can be smaller than the difference between the administratively-determined Net CONE (point "b") and the "true" Net CONE at which suppliers are willing to enter, deterring needed investment
- Performance risk of the current VRR curve is exacerbated by the asymmetric nature of the VRR curve (steeper to the right of point "b")

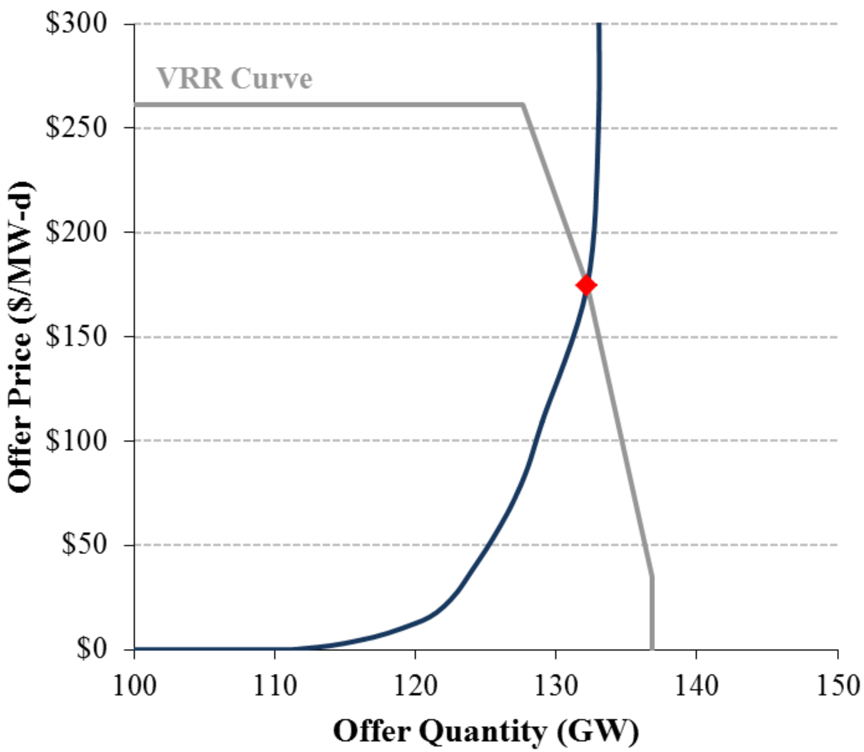
Explanation of Performance Risk (cont.)

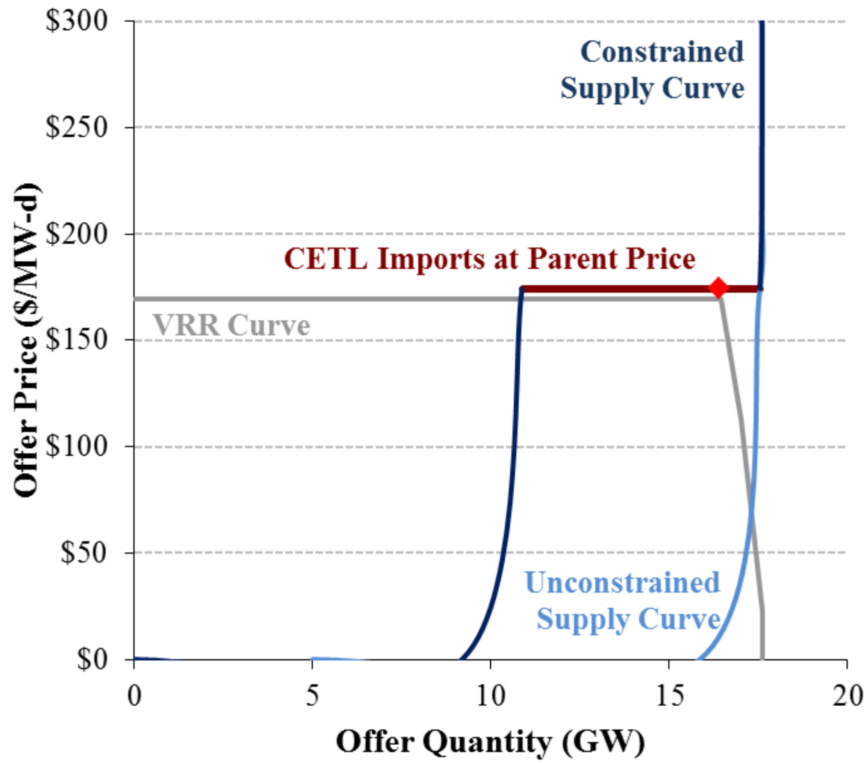
VRR Curves with E&AS Offset Equal to 25% and 75% of CONE



Example: VRR Curve Performance Risk

2010/11 VRR Curves and BRA Results for RTO and SWMAAC





- In 2010/11 SWMAAC cleared above the VRR cap for the LDA
- Had SWMAAC been much shorter, the LDA would still have had the same unconstrained price, resulting in inadequate local procurement

Hobbs Simulations with Alternative VRR Values

Simulation Results with Historic E&AS Offset	Fraction of Time Cleared Resources Exceed Requirement (%)	Realized Reserve Margin minus Target Reserve Margin (%)	Generator Profits after Capital and Operating Cost ($/kW-y)	Scarcity Revenue (Portion of E&A/S From Scaricity Pricing) ($/kW-y)	Average Capacity Price ($/kW-y)	Consumer Payments for Capacity and Scarcity ($/peak kW-y)
Original Hobbs Curve (*a* = 2 x CONE - E&AS = b + 1.0 x CONE)						
Average	77%	0.57%	17	19	109	151
Standard Deviation		*(5.3%)*	*(49)*	*(33)*	*(30)*	*(67)*
Settlment Curve: Current RPM VRR Curve (*a* = 1.5 x Net CONE)						
Average	26%	-5.18%	31	78	64	207
Standard Deviation		(6.2%)	(77)	(70)	(44)	(146)
Vertical Demand Curve (price cap = 2 x CONE - E&AS)						
Average	26%	-2.62%	72	49	133	222
Standard Deviation		*(6.2%)*	*(126)*	*(65)*	*(88)*	*(174)*
Settlement Alternative 1 (*b* ≥ 0, *c* ≥ 0, *a* ≥ 0.5 x CONE)						
Average	37%	-2.24%	26	42	95	170
Standard Deviation		*(5.6%)*	*(64)*	*(55)*	*(29)*	*(108)*
Settlement Alternative 2 (Alt. 1 w/ 20% limit on Net CONE reductions)						
Average	53%	-0.39%	17	24	104	151
Standard Deviation		*(5.3%)*	*(49)*	*(40)*	*(22)*	*(72)*
Settlement Alternative 3 (*b* ≥ 0, *c* ≥ 0, *a* = *b* + 0.5 x CONE)						
Average	55%	-0.47%	19	25	104	153
Standard Deviation		*(5.4%)*	*(53)*	*(42)*	*(25)*	*(79)*
Settlement Alternative 4 (*b* ≥ 0, *c* ≥ 0, *a* = 1.5 x CONE)						
Average	67%	0.24%	17	20	107	149
Standard Deviation		*(5.2%)*	*(48)*	*(34)*	*(26)*	*(67)*

Better

Current

Better

Recommendations

- We recommend PJM and stakeholders consider:
  - Raise point "a" to at least 0.5xCONE above point "b" (possibly to 1.0xCONE above "b" consistent with originally filed curve) to avoid collapsing the VRR curve and deterring needed offers when below reliability target – particularly if a normalized forward-looking offset cannot be developed before the next BRA
  - Confirm that Net CONE estimates cannot be less than zero for purpose of determining points "b" and "c" of the VRR curve
  - Renew effort to develop a normalized, forward-looking or equilibrium E&AS offset
- E&AS offset calibration to better reflect actual E&AS margins earned is also important, as discussed in prior section
- Maintain "level-nominal" CONE (rather than transitioning to "level-real") until these performance challenges are addressed

VRR Curve Slope

Considerations for the VRR curve slope

- Reasons to have a steep VRR curve:
  - Minimize under-procurement to protect resource adequacy
  - Minimize over-procurement to reduce costs
  - Have prices and procurement respond more quickly to changes in market conditions
  - Limit the impact of Net CONE changes
- Reasons to have a flatter VRR curve:
  - Limit the impacts of lumpy investments
  - Limit the impacts of changes in uncertain or unstable administrative parameters (modeled LDAs, CETL, load forecast, and reserve margin target)

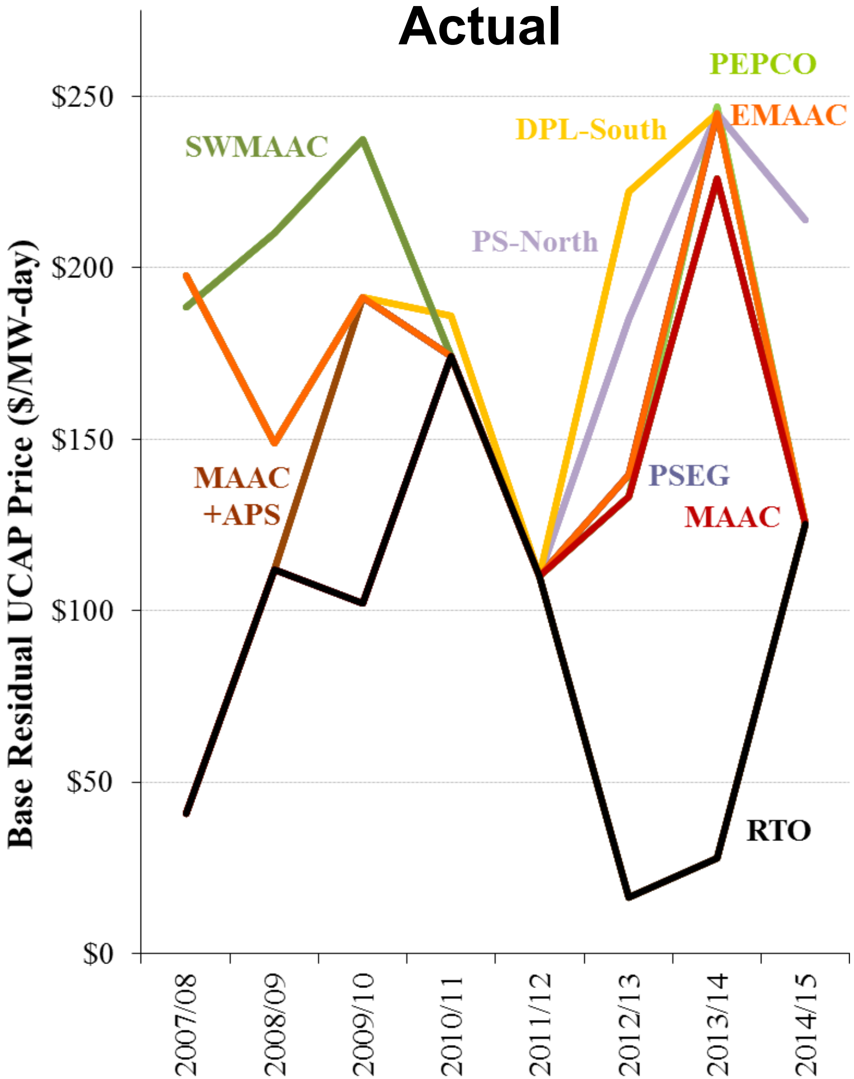
Questions Investigated

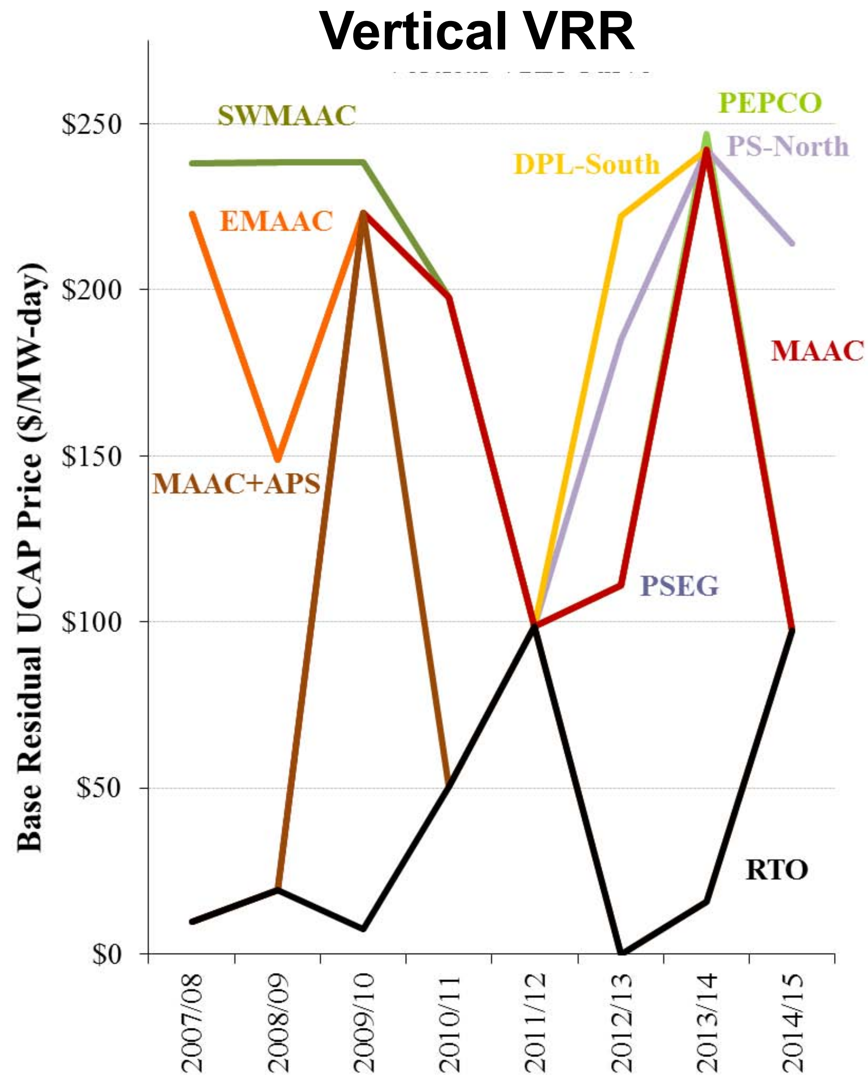
- How much is the current curve reducing price volatility relative to a vertical curve?
- How much further would price volatility be reduced by making the VRR curve flatter?
- Would LDA price volatility be reduced by making the VRR curve flatter in LDAs?

Simulation Approach

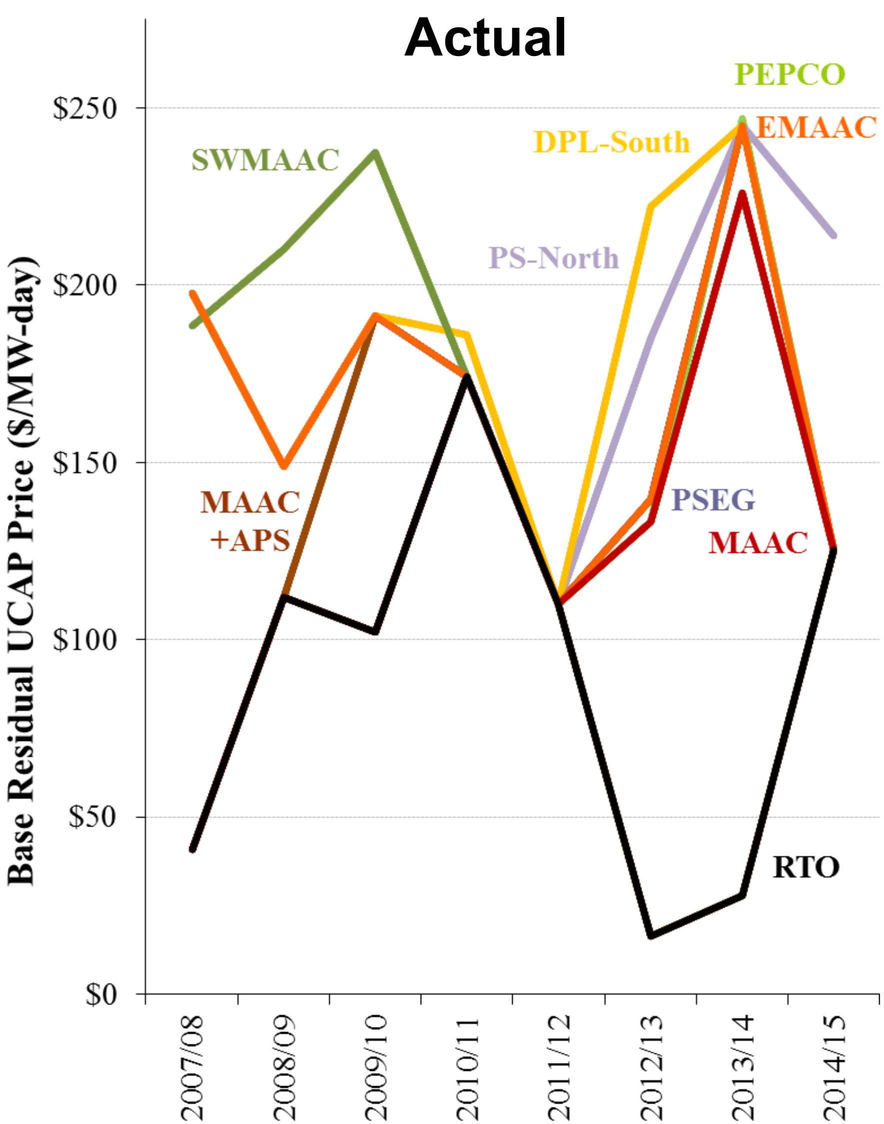
- Scenario analysis re-running historic auction results under various design changes
- Probabilistic Hobbs simulations with modeling refinements and updated parameters

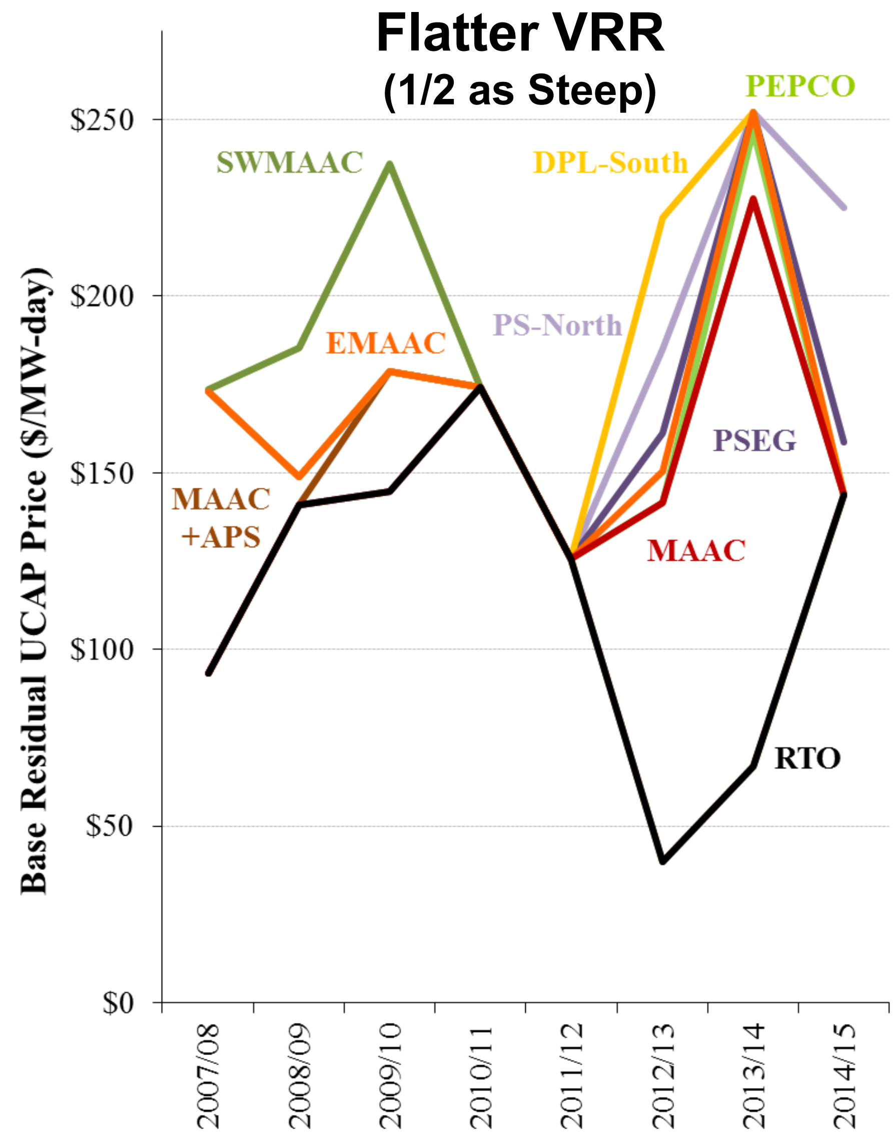
BRA Scenario Analysis: Vertical VRR Curve





BRA Scenario Analysis: Flatter VRR Curves

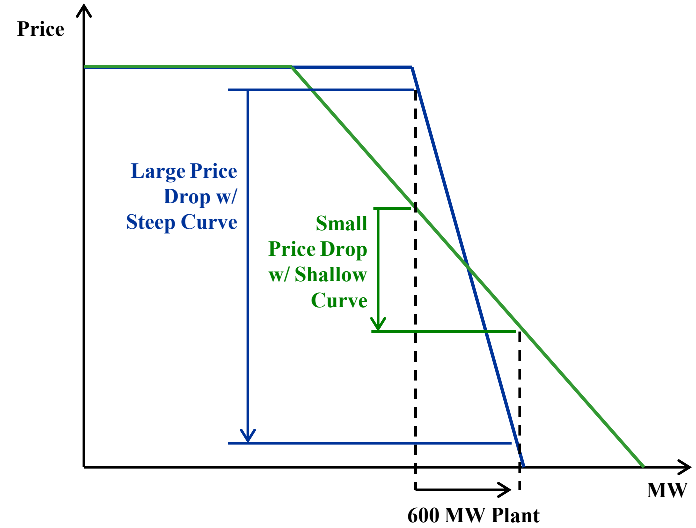




Flatter Slope of VRR Curve in Small LDAs

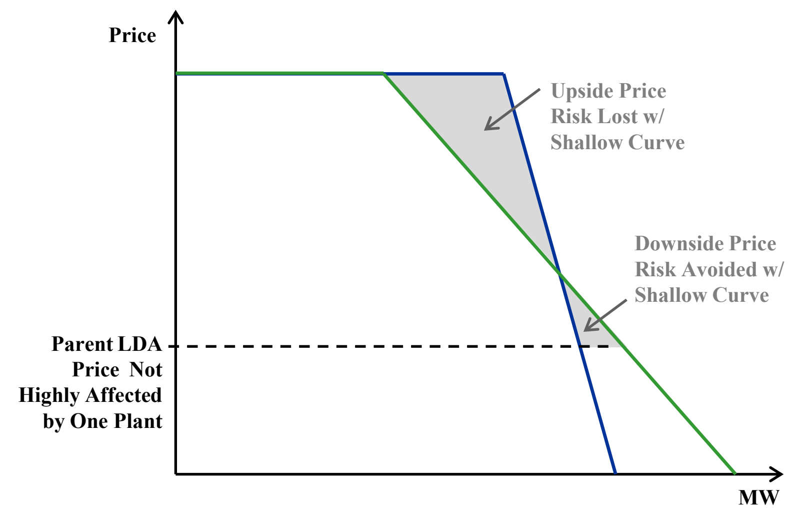
Considered Flatter Slope in Small LDAs

- Intuition: flatter VRR curve would provide more stability in small LDAs
- Preventing entry from crashing LDA price
  - In SWMAAC or PSEG, one 600 MW plant corresponds to a price change of zero to Net CONE
  - In DPL-S, PS-North, and PEPCO a 600 MW plant is the difference between the price cap and floor
- In a small stand-alone LDA a flatter VRR curve may be beneficial (top chart)



Asymmetric Risk Makes this Unattractive

- But small LDAs are already protected from downside price risk by the parent LDA (EMAAC or MAAC)
  - Substantial upside price risk is lost in small LDAs
  - Flatter curve avoids little downside price risk (unless the parent LDA price is far below Net CONE) but risks under-procurement
- Simulations of historic auctions confirm this result, showing very little impact on LDA price volatility



Summary of Findings

VRR Curve Slope

- Prices are less volatile than they would have been under a vertical demand curve, with the biggest impact in early years (which had steeper supply curves)
- Moderate additional price stability could be achieved from further flattening the VRR curve, but with substantial drawbacks:
  - Perpetuating capacity-long and capacity-short conditions
  - Increasing the magnitude of capacity excess and capacity shortage events
  - Increasing the influence of the administrative Net CONE calculation
- We do not see a compelling reason to revise the VRR curve slope or shape, and recommend that efforts instead be focused on other methods of reducing price volatility

VRR Curve Slope in Small LDAs

- We considered but recommend against developing a different VRR curve slope for small LDAs, primarily because of the asymmetric profile risk profile in a nested zonal capacity market

Contents

Major Changes in CETL

Year	Location or Auction		Causes of Major CETL Changes
2008/09	*EMAAC*	-	2,085 MW increase in EMAAC coincides with the modeling of key expected transmission upgrades in the LDA including transformers, capacitors, line segments, and other transmission elements.
2009/10	*EMAAC and SWMAAC*	-	575 and 781 MW increases in MAAC and SWMAAC coincides with several key expected transmission upgrades in these LDAs.
2012/13	*BRA in EMAAC*	-	Addition of Susquehanna-Roseland transmission line coincides with a relatively small CETL increase of 275 MW in EMAAC.
	1st IA in EMAAC	-	Delay of Susquehanna-Roseland transmission line causes CETL reductions of 1,455 MW in EMAAC and smaller reductions in PSEG and PS-North.
2013/14	*MAAC and SWMAAC*	-	1,917 MW decrease in MAAC and 675 MW decrease in SWMAAC attributed primarily to load increase in the northern Virginia area of Dominion from expected large data center loads.
	EMAAC	-	1,984 MW decrease in EMAAC attributed primarily to the deferred online date of the Susquehanna-Roseland 500 kV line.
2014/15	*MAAC, SWMAAC, and PEPCO*	-	Approximate 1,000 MW increases in MAAC, SWMAC, and PEPCO are attributed to the addition of Brambleton 500 kV substation and 500/230 kV transformer in Dominion.
	EMAAC	-	1,094 MW increase in EMAAC attributed to a 350 MW size reduction in the O66 generation project and a shift in the EMAAC load distribution profile.

Causes of CETL Uncertainty

- **Unpredictable Fundamentals:** changes in transmission plans, retirements, load growth, load distribution
- **Unpredictable Rule Changes:** criteria for modeling LDAs
- **Lack of Forward View:** insufficient information about CETL determinants and how CETL will change even if future market fundamentals and RPM rules are known
- **Insufficient Modeling Transparency:** lack understanding of CETL modeling, how easily the constraining elements could be relieved, and the scale of impact from relieving them
- **Modeling Sensitivity:** very sensitive to inputs (e.g., which resources are available and load distributions)

Recommendations to Increase CETL Transparency

We recommend that PJM reduce uncertainty by providing more information about expected future CETL values

- **Consider providing a CETL forecast consistent with RTEP**
  - Provide non-binding CETL outlooks for all modeled LDAs with RTEP cases: 10 year plan, 5 year plan, and 4 year retool (published 6-9 mo. before BRA parameters are finalized)
  - Final CETL determination would continue to be provided prior to each BRA (i.e., in January after updated load forecasts become available)
  - If practical, PJM could also provide sensitivity analyses (for example showing effects of removing at-risk generators)
- **Consider providing the CETL model (or modeling documentation) and data to market participants**
  - Will enable them to conduct their own sensitivity analyses and forecasts
  - Requires same CEII clearance needed for load flow cases
  - The only data that can’t be shared are the unit-specific EFORd data

Recommendations to Increase CETL Stability

Allowing easily-resolved constraints to limit CETL may be inefficient; it also makes CETL unstable because an upgrade could be made at any time. We recommend that PJM consider:

- **Identifying successive limiting elements and the CETL impacts of relieving those constraints**
  - PJM already indicates which transmission facility is limiting in N-1 operation
  - PJM should also indicate how much CETL would increase if that constraint were relieved, what the next limiting element would be, etc.
  - Will provide insight into CETL stability and QTU/ICTR opportunities
- **Facilitate opportunities for QTUs & ICTRs to upgrade CETL**
  - Providing this information (e.g., with 4-year RTEP retool *6 months prior* to each BRA) would allow identification of QTU or ICTR opportunities
  - QTUs or ICTRs clearing in the BRA would increase CETL when cost effective and prevent CETL from being inefficiently and inconsistently limited by easily-resolved constraints
  - With such a setup, PJM might consider increasing the CETO/CETL threshold for transmission planning

Deadband for Major Transmission Projects

Avoid excessive changes to transmission plans

- Many of the large changes in CETL have been caused by planned new transmission and unexpected changes in plans
- Instability is created with transmission plans added or removed whenever CETO/CETL move (even slightly) above or below 1.0
  - Often influenced by changes in short-term conditions, which is inefficient for assets with a 40-year life.
- Consider creating a "deadband" to reduce the frequency of changes and allow for BRA-based market response, such as:
  - Address reliability need with transmission project only if CETO/CETL > 1.02
  - Delay a previously-planned project only after CETO/CETL < 0.95
  - The 1.02 trigger point will also help elicit generation and DR solutions instead of pre-empting them with T solutions, without risking a major reliability shortfalls
  - We understand that PJM's Regional Planning Process Task Force (RPPTF) is already considering a deadband

Rationalizing RPM and RTEP

RPM and RTEP are inherently difficult to coordinate

- The locational "reliability" issue of CETO>CETL is mostly a locational resource adequacy issue: starts out with assumption about which capacity resources will be available in which locations
- Long lead-time of transmission planning means that the locational generation and DR additions and retirements must be guessed *before* capacity market results are known
- Danger in transmission planning is the possibility of pre-empting generation and DR solutions that would have been more economic

Economic "competition" between capacity and transmission

- Structuring a market that allows competition between generation and transmission is difficult and may be impossible in many cases
- However, we recommend that PJM, as part of its RTEP reform, consider options that would economically rationalize the process and its impact on RPM:
  - Consider adding economic criteria to the evaluation of transmission projects that serve a LDA resource adequacy function, including potential cost-benefit analyses compared to generation and DR alternatives
  - Consider special solicitations for lower-cost alternatives to identified transmission upgrades, including generation and DR

Maintaining Local Reliability w/o RMR Contracts

Reliability and RMR contracts due to optimistic CETL

- Determine if RMR based N-2 analyses could instead be included in the CETL determination (i.e., if reliability issue can be addressed by generic capacity within LDA)
- Consider developing CETL calculations based on generation that more closely coincides with RPM and potential unit-specific retirements, such as:
  - CETL modeled in RPM conditional on units that fail to clear the auction
  - Calculate CETL based on an exclusion of units with high BRA offers related to potential retirement (as approved by IMM)
  - When reducing LDA internal generation MW for CETL calculation, consider reducing internal MW in descending order of last BRA offer prices (indicating the likely order of non-clearing units)

Concerns in LDAs not modeled

- LDAs not modeled may become reliability concerns if significant retirements (e.g., 16% of the capacity in one zone did not clear in the 2014/15 BRA)
- Identify and model all LDAs that may be at risk for high retirements
- Uncleared capacity should be considered unavailable in subsequent auctions
  - Update CETO calculations accordingly
  - Model new LDAs in next incremental or base auctions if CETL/CETO < 1.15

LDA Modeling Structure

Concerns

- Nested LDA structure does not accurately model actual transmission capability (e.g., MAPP upgrade will allow transfer directly from Dominion to SWMAAC, not through western MAAC as is modeled under RPM)
- If a larger number of LDAs is modeled (as supply conditions tighten), then additional types of transfer capabilities will be needed

Recommendations

- We recommend that definition of LDA structures under RPM be made more general. Where relevant:
  - Allow for meshed zonal system that accounts for multiple import/export interfaces for individual LDAs (rather than enforcing a nested structure in all cases)
  - Allow for export-constrained zones or zones that may be either import-constrained or export-constrained
- Also recommend that transfer limitations and modeled LDAs be identified based on transmission capabilities, not necessarily based on historic TO boundaries

Improving the Transparency of Load Forecasting

Concerns

- Uncertain or poorly understood changes in load forecasts contribute substantially to uncertainty in RPM prices and quantities
- Uncertainty is inevitable and forecasts must change to reflect evolving data and consensus economic forecasts; however, given high stakes, increased efforts warranted to ensure accuracy, best practices, and transparency

Recommendations

- Improve documentation and stakeholder understanding of drivers behind updated forecasts
- Provide estimates of (weather normalized) forecasting uncertainty
- Consider providing semi-annual preliminary updates of load forecasts
- Continue existing efforts to refine load forecasting model and process
- Collect utility load forecasts as additional reference points
- Retain academic advisors to support PJM load forecast team

Concerns

With DR now providing ~10% of total need, it is important to review DR-related provisions of RPM:

- Mechanisms to ensure that all DR types will be able to respond as claimed
- Comparability of obligations of DR and generation
- UCAP rating: DR/FPR factors

PJM already addressed two important initial design issues:

- Eliminated ILR, starting with the 2011/12 delivery year
- Established differentiated products, starting with the 2014/15 delivery year

For this report, we evaluated:

- The new multi-product construct to accommodate different types of DR
- Mechanisms to verify and enforce that resources committed will perform as promised
- Determination of the (UCAP) capacity value for DR
- Potential future directions to recognize the capacity value of other non-traditional resources (e.g., PRD)

Assurance of DR Quality

Activity	Timing	Assurances & Verification in Place	Potential Enhancements
Qualification of New Resources	≥ 15 days prior to an RPM auction	**Review of DR Plan** (project description; customer recruiting plan & milestones; MW value of DR; key assumptions) **Verification that RPM Credit Limit** has been posted **"Provisional approval"** of DR MODs (assigns nominated value to individual resources) if above requirements are met	None identified.
Tracking	Anytime between BRA and Delivery Year	**Verify adherence to the schedule in the DR plan** at PJM's discretion at any time including, but not limited to, 30 days prior to each IA; mostly relies on suppliers to develop planned resources and manage deficiencies by procuring replacement capacity (else risk penalties).	Consider requiring CSPs to periodically report their progress against DR plans.
Registration in Emergency Load Response Program	Jan - May prior to Delivery Year	Requires submittal of some customer-specific information Must be in "Approved" status prior to start of DY to avoid commitment shortfall & Deficiency Charge	**Introduce audits of contracts and physical loads to verify zonal resource portfolio abilities to curtail as *frequently* and *seasonally* as represented** (esp. for Annual and Extended Summer), with appropriately punitive penalties to incent CSPs to represent accurately.
Performance & Testing	During Delivery Year	**Penalty/credit** for under-performance during emergencies (Load Management Events) **Penalty** for failing tests, but CSPs initiate tests; can test repeatedly and submit the best results. Tests show MW but not ability to respond frequently or seasonally.	**Conduct random testing initiated by PJM**; limit CSPs' ability to selectively pick test results; extend duration of tests to multiple hours, e.g., 6; provide energy payments during tests.

Other DR-related Recommendations

Multiple capacity products

- Consider allowing other resource types with limited availability (e.g., generation with seasonally-differentiated capabilities and costs) to make linked offers as Limited or Extended Summer resources
- Consider re-classifying some seasonal resources (e.g., some energy efficiency or PRD based on seasonal loads) from Annual to Extended Summer

UCAP Value of DR

- *FPR and DR Factor*: Eliminate both for GLD-type DR, counting at its face value; maintain the FPR gross-up (or perhaps more) for FSL-type DR
- Derate capacity values for weak performance
- Consider working with the EDCs to improve their methodologies for assigning PLCs

Price Responsive Demand

- PJM and its stakeholders should integrate PRD into RPM by finalizing the proposal that PJM has already proposed

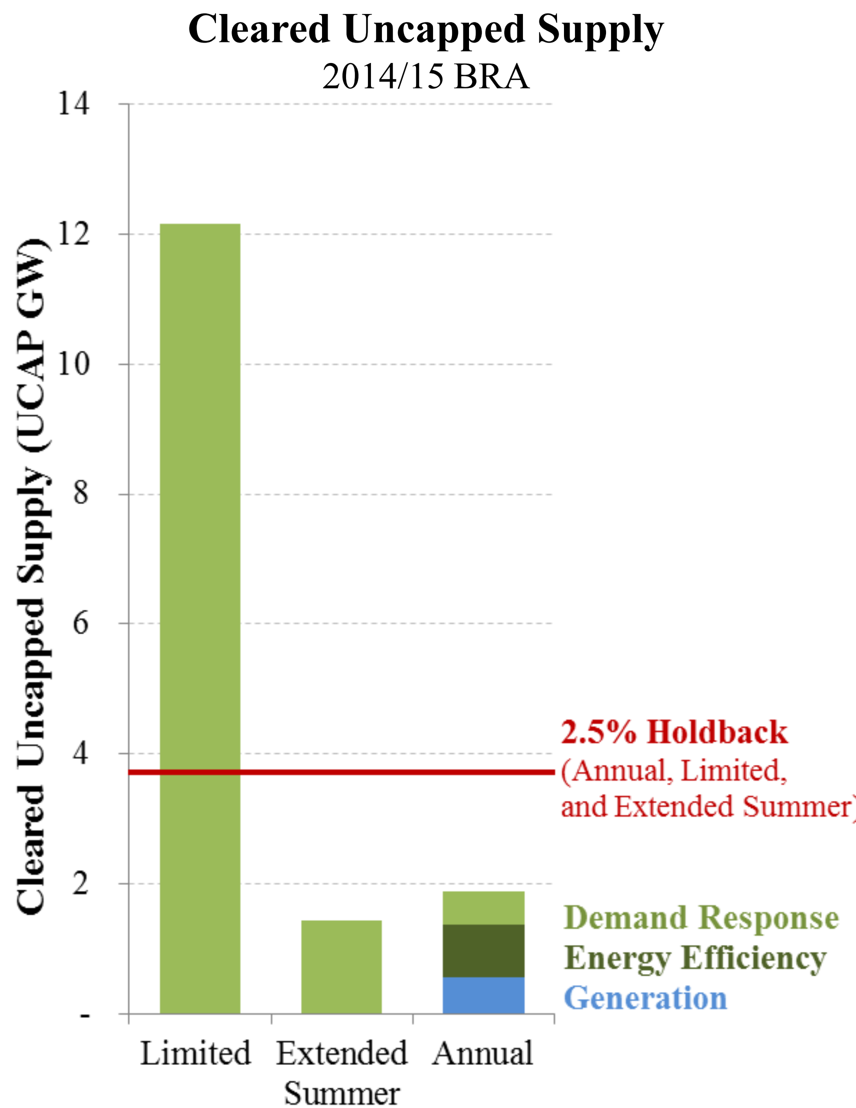
2.5% Short-Term Resource Procurement Target

Concerns

- Generation owners, TOs, and the IMM are concerned that the holdback combined with must-offer obligation artificially reduces BRA prices
- Reliability risk if unexpected load growth or less than 2.5% becomes available in the IAs

Review of Available Evidence

- IA prices substantially lower than BRA prices: evidence against artificial price reduction
- Cleared unmitigated Limited DR exceeds 2.5% → no price reduction concern
- Cleared, unmitigated Annual and Extended Summer supply less than 2.5% → cannot rule out the possibility that the holdback depresses prices



2.5% Short-Term Resource Procurement Target

Recommendations

- Maintain the 2.5% holdback for the total requirement
    - Helps prevent over-procurement
    - Efficiently accommodates short lead-time DR without depressing BRA prices
- Eliminate the holdback for Annual and Extended Summer resources
    - Avoids artificial price reduction (because 2.5% exceeds unmitigated portion of these supplies)
    - Reduces the risk of under-procuring existing Annual resources, which might retire if not clearing in BRA, but could create shortage of Annual resources in IAs
    - Reflects that most annual resources are generation, with few new resources available on a short-term basis

MOPR Concerns

Wholesale markets need to be protected from manipulation. However, even low offers may be competitive:

- Developer might offer below the Net CONE value if anticipating rising spark spreads (relative to 3-year historic average), rising future equipment costs, or faced with expiring options
- Resources with additional revenue sources (e.g., renewables or cogeneration)

Risk of not clearing creates uncertainty for contracting and self-supply

- Resources will rationally offer into RPM as a price taker if the development of the resource is already committed and not contingent on the auction outcome
- MOPR may prevent clearing, requiring double procurement
- One might argue that the resource is uneconomic and should not be developed if it does not clear in the RPM auction.
  - But lack of perfect information and foresight will result in some resources being planned or contracts being signed at prices that turn out to be above market.
  - It would be unrealistic to expect market participants to perfectly forecast uncertain annual capacity prices. (Unpredictability is a principal reason to sign long-term contracts!)

Current MOPR rules may undermine bilateral long-term contracting, self supply, and force some entities switch to FRR inefficiently

MOPR Recommendations

RPM should complement but not supplant a competitive bilateral market and self-supply:

- Need to enable legitimate, non-manipulative, long-term contracting
- Develop an exemptions process that balances the risk of false positives (over-mitigation) against the risk of false negatives (under-mitigation)

Consider exempting from mitigation certain types of offers, including:

- New generation units that have won a competitive, non-discriminatory RFP open to new and existing resources
- Self-supply resources offered into RPM by vertically-integrated LSEs if the resource is the result of a deliberative planning process and the LSE is not substantially net short in RPM
- Any other resource offers by entities if they (and/or their contractual counterparties or constituents can) verify that they are not substantially net short in RPM (and, thus, would not benefit from suppression of RPM capacity prices)

Offer Cap at Zero Price

Increase Offer Cap Floor

- Current offer caps are mostly at zero, as calculated for units that would not retire or mothball even without capacity payment
- Fails to consider the cost of the capacity obligation as a stand-alone commitment (three year forward, must offer obligation)
- We recommend increasing the lowest offer caps above zero for mitigation purposes to account for the cost and risks of taking on the capacity obligation including, at a minimum, the risk of performance penalties
  - Floor on offer mitigation does not create a floor for capacity prices as participants are still free to bid at zero
  - But avoids forcing market participants into obligations without recognition of their costs and risks

Options to Support Long-Term Contracting

Concern:

- Stakeholders have expressed increasing interest in supporting new investment by expanding NEPA to address price volatility (especially in LDAs) and the lack of multi-year forward price certainty within RPM
- Option would be broad multi-year lock in available for all resources

Recommendation:

- We do not recommend expanding NEPA to other supply or extending the term (though current design still helpful in LDAs to address "lumpy" investments)
- Instead, we recommend adding options for facilitating longer-term bilateral contracting, hedging, and providing forward price transparency, such as:
    - PJM's proposal of centralized, voluntary multi-year auctions; or
    - A continuously-clearing over-the-counter capacity exchange similar to other commodity futures markets for trading energy and natural gas
    - Under either option substantial information should be posted (including clearing volumes, clearing prices, and bid-ask spreads even if no transactions clear)
- If, over time, long-term contracting is *proven* to be insufficient to support needed entry (a problem not observed to date), PJM and stakeholders could consider mandatory long-term procurement of portion of resource requirement (e.g. rolling 7-year contracts for 7% of total requirement); but risks mandating inefficient long-term contracting