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December 1, 2011

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER12-___-000

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, hereby submits revisions to the PJM Open Access Transmission Tariff ("Tariff") to revise certain elements of the Reliability Pricing Model ("RPM") following a comprehensive independent review of RPM and an intensive stakeholder process to consider changes to RPM's auction parameters.

The enclosed changes affect key parameters that will govern RPM's next three-year forward Base Residual Auction,[1] and that PJM is required to post by February 1, 2012. PJM therefore requests that the enclosed revisions become effective on January 31, 2012.

I. INTRODUCTION AND SUMMARY.

This filing fulfills two important RPM Tariff obligations: 1) a triennial review of the shape of the Variable Resource Requirement ("VRR") Curve[2] used to clear the RPM auctions and key inputs to that curve, i.e., the Cost of New Entry ("CONE")[3] by a representative new power plant and the Net Energy and Ancillary Services Revenues[4] ("EAS") that plant would be expected to earn in the PJM markets; and 2) a review of

1 The Base Residual Auction (or "BRA"), as defined in the Tariff, is the principal RPM auction, which secures commitments for capacity three years forward. *See* Tariff, Attachment DD, section 2.5 (eTariff record OATT Attachment DD.2).

2 *Id.*, section 5.10(a)(i) – (iii) (eTariff record OATT Attachment DD.5.10).

3 *Id.*, section 5.10(a)(iv) (Etariff record OATT Attachment DD.5.10).

4 *Id.*, section 5.10(a)(v) (eTariff record OATT Attachment DD.5.10).

RPM's performance since its implementation in 2007. PJM retained an independent consultant, The Brattle Group ("Brattle") to assist with the triennial review and conduct the performance assessment.

Brattle's performance assessment concluded that "RPM is performing well[;] . . . has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements[; and]. . . has reduced costs by fostering competition among all types of new and existing capacity, including demand-side resources."[5] Brattle nonetheless recommended certain changes to further improve RPM. On the RPM elements that are the focus of the triennial review, Brattle recommended changes to the VRR Curve shape, CONE values, and the EAS offset methodology. In connection with its performance assessment, Brattle recommended changes to several other aspects of RPM. Based on the Brattle reports and PJM's own analysis, PJM staff advised stakeholders of its recommendations concerning changes to RPM.

PJM and its stakeholders then devoted several months to intensive discussion of these issues. Based on the Brattle reports, PJM staff recommendations, and stakeholder input, the PJM Board determined to revise the RPM parameters as follows:

- adopt the updated CONE values from Brattle's detailed "bottom-up" analysis for the 2015/16 Delivery Year[6] (in $/MW-year):[7]

  CONE Area 1: $134,000
  CONE Area 2: $123,700
  CONE Area 3: $123,500
  CONE Area 4: $130,100
  CONE Area 5: $111,000

  and set the RTO region-wide value at the median Net CONE of all CONE Areas;

- set the highest point on the VRR Curve equal to the greater of gross CONE or 1.5 times Net CONE to avoid potential collapse of the curve when historic energy revenues used to determine the EAS offset are high;

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5 The Brattle Group, Second Performance Assessment of PJM's Reliability Pricing Model (Aug. 26, 2011) ("RPM Performance Assessment"), at i. (Attachment E)

6 A Delivery Year is a twelve-month period beginning on June 1 of a calendar year and ending on May 31 of the following calendar year.

7 The referenced CONE Areas are sub-regions of PJM, as described below. Expressed in $/MW-day these values are $367.12/MW-day for CONE Area 1; $338.90/MW-day for CONE Area 2; $338.36/MW-day for CONE Area 3; $356.44/MW-day for CONE Area 4; and $304.11/MW-day for CONE Area 5.

- revise the EAS methodology to better reflect likely dispatch operations by assuming commitment of the CONE plant first against day-ahead locational marginal prices ("LMPs") and then, to the extent not committed day-ahead, dispatch against real-time LMPs; and

- retain the 2.5 percent Short-term Resource Procurement Target ("STRPT") or "hold-back" that defers resource procurement for a portion of the overall load in RPM from the Base Residual Auction to the Incremental Auctions, but eliminate the current application of the hold-back to the separate minimum procurement requirements for two distinct resource categories, i.e., Annual Resources and Extended Summer Resources.

This filing also contains several related changes to RPM. First, PJM is updating the CONE value of a combustion turbine ("CT") plant used to help screen offers under RPM's Minimum Offer Price rule ("MOPR") to match the updated CONE values for the VRR Curve, and is using the equally detailed combined cycle ("CC") plant cost estimates Brattle provided in its report to update the values used under MOPR to screen offers from CC plants. Similarly, PJM is taking into account the commitment of both the CT and CC plants in the day-ahead market when calculating the MOPR screen levels for those plant types, in the same manner as proposed for the EAS calculations used for the VRR Curve.

Second, PJM is making several stakeholder-approved, clarifying changes to RPM's New Entry Price Adjustment ("NEPA"). PJM also is recognizing the extensive effort to date by stakeholders to develop a voluntary, non-discriminatory, long-term auction to supplement RPM by setting a date certain for PJM to file Tariff changes with the Commission next year for such an auction. There is strong stakeholder sentiment in favor of such an approach as an alternative to, or possible replacement for, NEPA, but more details with respect to that approach need to be developed before it can be submitted to the Commission.

The PJM stakeholder process has been invaluable to the development of this filing. One of PJM's most senior committees, the Markets and Reliability Committee ("MRC"), devoted twenty special meetings this year exclusively to RPM topics. RPM, including the matters addressed by this filing, also was considered at several regular meetings of the MRC and the PJM Members Committee. The PJM Board also received valuable input from a variety of stakeholders, including state commissions, regarding the performance of, and suggested improvements to, RPM before it voted to authorize this filing. The stakeholder's intense focus on RPM this year heavily influenced the changes presented in this filing, but it also highlighted that some of the Brattle recommendations will require additional stakeholder discussion that may result in possible additional changes in the future. Additionally stakeholder concerns related to the obligations in the PJM Day-ahead Energy Market of resources committed as PJM capacity and the comparability of capacity resource response requirements in the energy markets were outside the scope of the RPM parameter review and will be addressed in subsequent stakeholder discussions. Thus, PJM's submission of this section 205 filing with the specific changes that are the focus of the triennial review and a few other selected consensus or high-priority changes to RPM does not foreclose those other areas of inquiry. To the contrary, PJM is committed to building on the stakeholders' productive efforts to date and continuing to address remaining issues or concerns with RPM in the stakeholder process.

II. TARIFF CHANGES RESULTING FROM THE TRIENNIAL REVIEW OF RPM.

A. Background.

The Tariff requires that for the 2015-16 Delivery Year and "for every third Delivery Year thereafter," PJM "shall perform a review of the shape of the [VRR] Curve . . . based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis."[8] PJM then is required to recommend either that the existing VRR Curve shape be modified or retained, post its recommendation, and review it through the stakeholder process. If PJM proposes that the VRR Curve shape be modified, it must present its proposal to PJM stakeholders "on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied."[9] After the PJM Members review any such proposed change, they are required to vote "to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied."[10] The PJM Board of Managers then will consider any proposed modification to the VRR Curve shape, and PJM must file any changes to the VRR Curve shape approved by the PJM Board with the Commission "by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied."[11]

The Tariff prescribes essentially the same process for consideration of possible changes to the CONE values or the EAS offset methodology.[12]

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8 Tariff, Attachment DD, section 5.10(a)(iii) (eTariff record Attachment DD.5.10).

9 *Id.*, section 5.10(a)(iii)(A) (eTariff record OATT Attachment DD.5.10).

10 *Id.*, section 5.10(a)(iii)(C) (eTariff record OATT Attachment DD.5.10).

11 *Id.*, section 5.10(a)(iii)(D) (eTariff record OATT Attachment DD.5.10).

12 Tariff, Attachment DD, section 5.10(a)(vii)(C) and (D) (eTariff record OATT Attachment DD.5.10).

PJM adhered to this prescribed process this year and, based on the Brattle analyses and PJM staff's analyses, proposed Tariff changes to each of the three identified parameters, i.e., the VRR Curve shape, the CONE values, and the EAS revenue offset estimating methodology for implementation in connection with the May 2012 BRA for the 2015-2016 Delivery Year.

PJM's recommendations, and alternative recommendations from the stakeholders, were discussed and developed at the special MRC RPM meetings on a distinct "Triennial Review Track." To meet the Tariff-prescribed October 31 deadline, the Members were asked to vote at the October 20, 2011 Members Committee meeting on the status quo (no Tariff changes for the Triennial Review), the PJM recommendations, and four stakeholder-developed alternatives, known as Packages, 10, 11, 12, and 13. The Members strongly opposed a status quo approach, signaling their strong desire for changes to the RPM auction parameters before the next Base Residual Auction. None of the specific change proposals reached two-thirds sector-weighted support, but Package 13 was favored by over 62 percent of the Members (on a sector-weighted basis).

Taking the stakeholder views into account, the PJM Board has directed PJM to file the Package 13 approach to the triennial review issues, with one variation, as discussed below.

B. Change to VRR Curve Shape.

1. <u>Background.</u>

The VRR Curve is an administratively determined demand curve that is used, in combination with the supply curve formed from capacity supplier sell offers, to clear the RPM auctions. The Tariff defines the VRR Curve as a set of lines connecting several price-quantity points that are stated as multiples or fractions of the Net Cost of New Entry (on the price axis) and the target Reliability Requirement[13] (on the megawatt quantity axis[14]). Higher prices (above Net CONE) are associated with capacity shortage conditions (generally below the target Reliability Requirement[15]) and lower prices are associated with excess capacity conditions. The line segment that produces the highest price is for any shortage condition in which capacity is three percentage points below the approved Installed Reserve Margin (or lower). The current effective Tariff sets that price as 1.5 times the Net CONE.

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13 *Id.*, section 2.55(eTariff record OATT Attachment DD.2).

14 Capacity levels are on an "unforced capacity" basis, i.e., discounted for expected unforced outages.

15 More precisely, the 2006 RPM settlement associated Net CONE with a capacity level one percentage point above the Reliability Requirement.

Net CONE is calculated by subtracting from CONE (the levelized capital costs and fixed operations and maintenance ("O&M") expenses of a new plant) the EAS Revenues (the revenues such a plant could be expected to earn in the PJM energy and ancillary services markets). Using probabilistic market simulations, Brattle found in the assessment that the current VRR Curve design "risks the collapse of the entire VRR curve whenever historical energy margins spike (e.g., due to unusual weather, outages, or other unexpected scarcity events)."[16] In cases where the EAS offset "reach[es] or exceed[s] the value of CONE, the entire VRR curve disappears (i.e., there is no demand for capacity [at a non-zero price]), which can leave the market 'stuck' at reserve margins that remain well below reliability targets."[17] Brattle observed that even if EAS revenues were not so high as to cause a complete collapse of the curve, the current design of the VRR Curve "does not provide the investment signals that can be depended upon to maintain reliability targets;" for example, elevated EAS revenue offsets could cause the 1.5 times Net CONE cap on the VRR Curve to "drop[] to levels less than generation developers' actual net cost of new entry."[18]

Brattle therefore recommended, as a means "[t]o guard against such outcomes and maintain investment signals that can reasonably support achieving reliability targets," that the cap of the VRR curve be set to exceed the next lowest defined point on the curve (the Tariff-defined point "2," which associates Net CONE with the Reliability Requirement plus one percent) "by at least 0.5 × CONE and perhaps by as much as 1.0 × CONE."[19] Brattle contrasted this with the current rule, which sets the cap at only 0.5 × Net CONE over the point 2 price level. Brattle advised that "[t]his would reduce the likelihood that the cap is too low to attract offers under a variety of circumstances."[20] As a real-world example of the benefits of this revision, Brattle observed that it would have avoided "a problem encountered in [the] SWMAAC [Locational Deliverability Area[21] ("LDA")], where a low price cap (relative to the price in the MAAC parent LDA) prevented the LDA from price-separating and continuing to procure local capacity in the 2010-11 auction in spite of shortages."[22] More broadly, Brattle's probabilistic market

16 RPM Performance Assessment at viii.

17 *Id.*

18 *Id.*

19 *Id.* at viii - ix.

20 RPM Performance Assessment at ix.

21 *See* Tariff, Attachment DD, section 2.38 (eTariff Record OATT Attachment DD.2).

22 RPM Performance Assessment at ix.

simulations indicated that increasing the VRR Curve cap in this fashion would significantly improve the VRR Curve's ability to meet reliability targets.[23]

The stakeholders' Package 13 took a slightly different approach to addressing the concern identified by Brattle. Brattle's proposal to define the highest segment of the curve by adding as much as all of the gross CONE to the Net CONE would protect against complete collapse of the curve or inadequately low price signals under very high EAS conditions, but also could significantly raise the curve (compared to the current design) during normal or low EAS conditions, as shown in the comparison below:

EAS	0	.25 CONE	.333 CONE	.5 CONE	.75 CONE	CONE
CONE - EAS (i.e., Net CONE, VRR Point 2)	CONE	.75 CONE	.667 CONE	.5 CONE	.25 CONE	0
Brattle/PJM Recommendation VRR Point 1 *CONE +VRR Point 2*	2 CONE	1.75 CONE	1.667 CONE	1.5 CONE	1.25 CONE	CONE
Package 13 Point 1 *Higher of 1.5 Net CONE or CONE*	1.5 CONE	1.125 CONE	CONE	CONE	CONE	CONE
Status Quo Point 1 *1.5 Net CONE*	1.5 CONE	1.125 CONE	CONE	.75 CONE	.25 CONE	0

As can be seen, under the Brattle recommendation (assuming, as PJM initially proposed to stakeholders, that the full CONE is added to the point 2 price of Net CONE), if EAS revenues are equal to one-quarter, one-third, or one-half of the gross CONE level, the Brattle recommendation, initially supported by PJM, would yield price values for Point 1

23 *Id.* at 99.

that are 56% to 100% higher[24] than under the current VRR Curve. Yet such EAS proportions to CONE are in the range of those posted for recent RPM BRAs.[25] These types of EAS levels are not the anomalously high EAS conditions that Brattle found in its probabilistic market simulations could lead to significantly degraded VRR Curve performance.

Package 13 therefore proposed to more narrowly target the curve collapse concern by setting a gross CONE floor under the high-price segment of the VRR eCurve. Under normal or low EAS conditions, the VRR Curve will be just as it is today. But when unusually high EAS conditions might result in a very large offset to CONE and produce an unacceptably low value for the portion of the curve at 1.5 X Net CONE that is intended to reflect shortage conditions, that part of the curve will not be allowed to drop below gross CONE. The chart above also compares the point 1 price values between the Brattle proposal initially supported by PJM and the Package 13 approach and shows that the Package 13 approach adequately addresses the "curve collapse" concern. Moreover, even beyond the anomalous conditions that might provoke a total curve collapse, the Package 13 approach assures new entry project developers that, even if energy prices spike for a few years before an auction, the clearing price under tight capacity conditions (3% or more below the installed reserve margin) will cover the full Cost of New Entry, with zero assumed contribution from energy or ancillary service revenues.

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24 When the EAS revenues equal one-half the value of CONE, the current Point 1 on the VRR Curve equals .75 times CONE. Under the Brattle/initial PJM recommendation, Point 1 would be double that, i.e., 1.5 times CONE. When EAS values equal one-quarter the value of CONE, the current Point 1 on the VRR Curve equals 1.125 times CONE, while the Brattle/initial PJM recommendation would put Point 1 more than 50% higher, at 1.75 CONE.

25 For example, in the past three BRAs, the EAS offset for 4 of the 5 CONE Areas has been in the range of 24-50% of the CONE value; in CONE Area 3, it has been below 10%:

	CONE Area 1	**CONE Area 2**	**CONE Area 3**	**CONE Area 4**	**CONE Area 5**
2014/2015	32.1%	35.4%	6.1%	24.0%	29.5%
2013/2014	32.4%	36.4%	6.7%	23.3%	31.1%
2012/2013	40.5%	46.6%	9.6%		

2. Proposed Tariff Change.

To adopt the stakeholders' Package 13 change on this issue, PJM is revising the Tariff's definition of point 1 on the VRR curve so that the price element is based on "{the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]}."[26] Whichever of these two values is used (i.e., gross CONE or 1.5 X Net CONE), it will be converted to an unforced capacity basis by the remaining unchanged language of the section.

C. Updates to the Cost of New Entry.

1. Background.

The Cost of New Entry is an estimate of the total project capital cost and annual fixed O&M expenses of a new generating plant of a type likely to provide incremental capacity to the PJM Region in the forward Delivery Year addressed by the RPM auctions. The Tariff defines that representative new entry plant, or "Reference Resource," as a combustion turbine power plant.[27]

The CONE values as initially stated in the Tariff when RPM was first adopted in 2006, and as updated in 2009, have consistently been based on detailed, "bottom-up" estimates of the components of a representative new entry project.[28] Thus, capital costs include, for example, the turbine power package and other major materials, land, station equipment, buildings, necessary gas pipeline and electric transmission infrastructure, emissions control equipment, permitting costs, and any contingency. The ongoing fixed O&M expenses include, for example, labor, outside contractor costs for operations or maintenance, property taxes, insurance, overheads, and regulatory expenses. The CONE in each case was developed using a financial model that includes estimates of the likely debt cost, required internal rate of return, income taxes, and the project's economic life. Each CONE estimate has been provided by independent expert consultants, relying to the extent necessary on specialized expertise of other engineering or consulting firms with project management, O&M, permitting, environmental, or other experience.

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26 Tariff, Attachment DD, section 5.10(a)(i) (eTariff record OATT Attachment DD.5.10).

27 *Id.* (eTariff record OATT Attachment DD.2).

28 *See, e.g.*, PJM Interconnection, L.L.C., 126 FERC ¶ 61,275, at P 36 (2009) (*"March 2009 RPM Order"*) ("PJM provided a detailed engineering study to support the CONE values contained in [its original] filing [and] [t]hat study also shows that the CONE values [ultimately proposed by PJM] are just and reasonable").

The Tariff contains separate CONE estimates for each of five "CONE Areas" that are defined in terms of the transmission owner zones they encompass, i.e.:

- CONE Area 1: Eastern MAAC (PS, JCP&L, AE, PECO, DPL, RECO);
- CONE Area 2: Southwest MAAC (PEPCo and BG&E)
- CONE Area 3: Rest of RTO (AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK);
- CONE Area 4: Western MAAC (PPL, MetEd, Penelec); and
- CONE Area 5: Dominion.

In 2009, the Commission approved a mechanism for automatic updates to the CONE values based on changes in a well-recognized utility construction cost index, known as the Handy-Whitman index, that "supplies a known and unbiased adjustment factor to change CONE values in years that are not subject to a full review."[29] PJM still must review the CONE values every three years, and retains the right at any time to file under section 205 to change any CONE values. The index ensures that the CONE values will be kept up to date with the latest trends in electric plant construction costs in the years between PJM's submission of section 205 CONE changes.

For this triennial review, PJM followed the same approach that yielded the CONE values previously approved by the Commission. In addition to the RPM Performance Assessment, Brattle prepared a detailed estimate of the Cost of New Entry for use in the VRR Curve. The results of Brattle's review and analysis are set forth in its report entitled "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM" ("2011 CONE Study"). Attached as Exhibit 2 to Dr. Newell's affidavit. A copy of that report is included with this filing, along with an affidavit of Dr. Samuel A. Newell, the Brattle Principal who led the CONE review and analysis. As explained by Dr. Newell, Brattle prepared the 2011 CONE Study in cooperation with CH2M HILL, a major engineering, procurement, and construction company with extensive experience in the design and construction of power plants, and Wood Group, a power plant O&M services provider.

The 2011 CONE Study, in its scope, approach, and level of detail, generally tracks the prior studies accepted by the Commission as adequate support for new RPM CONE values.

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29 *PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,090, at P 38 (2009) ("*October 2009 RPM Order*").

2. Resource Type.

PJM proposes no change to the current Tariff requirement that the "Reference Resource" used for the CONE estimate is a combustion turbine ("CT") power plant. Moreover, as the Commission has recognized,[30] a Net CONE based on a combustion turbine plant will have the lowest EAS offset of any resource type, and therefore would be the least affected by possible variance of actual energy market conditions from the conditions implicitly assumed in the EAS estimate.[31]

PJM is, however, updating the Reference Resource definition to reflect the more efficient heat rate produced by the latest combustion turbine model that is assumed for the CONE estimate, and to recognize differing requirements among the CONE Areas for emissions control technology..

3. Updated CONE Values.

As explained by Dr. Newell, Brattle reviewed and updated the technical specifications of the reference CT plant based primarily on the "revealed preference" of generation developers in the PJM Region and around the U.S. as reflected by recent installations of CT plants. Based on those considerations and discussions with CH2M HILL, Brattle based the CONE on a multi-turbine configuration employing the General Electric Frame 7FA turbine (as have all prior RPM CONE estimates) updated to reflect the latest 7FA turbine model, which provides higher installed capacity and a more efficient heat rate.[32] As more fully explained in the 2011 CONE Study, the CT plant configuration includes selective catalytic reduction ("SCR") technology to control nitrogen oxide ("NO_x") emissions where needed to meet air quality requirements, based on emerging trends in air quality regulation and simple-cycle turbine project development.[33]

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30 *March 2009 RPM Order* at P 39 ("combined cycle plants have more variable EAS revenues, and therefore, present significant estimating uncertainties").

31 By comparison, the gross CONE estimate is likely to be less variable, simply because plant construction costs are less volatile than energy prices.

32 The plant's net heat rate is 10.094 MMbtu/kWh at 59 °F with SCR technology and 10.036 MMbtu/kWh at 59 °F without that technology.

33 Specifically, SCR is included in the plant configurations in CONE Areas 1, 2, 3, and 4, but not in CONE Area 5, in accordance with Brattle's findings on this issue..

Brattle identified an appropriate site within each CONE Area for construction of the representative plant based on considerations including proximity to electric transmission infrastructure, access to major natural gas pipelines, site attractiveness as indicated by recently built power plants, and availability of vacant industrial land.

The CONE estimates assume a project entering service by June 1, 2015 and are calculated on a levelized basis over the new entry plant's assumed twenty-year life. The 2011 CONE Study found that, when using a nominal levelized financial model, the estimated June 1, 2015 CONE figures for the CT plant in each CONE Area are as follows:

CONE Area	CT Level-Nominal Gross CONE *($/MW-y)*
CONE Area 1	$134,000
CONE Area 2	$123,700
CONE Area 3	$123,500
CONE Area 4	$130,100
CONE Area 5	$111,000

These CONE values are lower for each CONE Area than those that would result from adjusting the 2014-15 Delivery Year values produced under the current Tariff for one year of inflation. As explained in the 2011 CONE Study, Brattle's 2011 estimates are lower primarily due to reductions (relative to inflation-adjusted prior CONE estimates) in equipment, materials, and labor costs, as well as economies of scale associated with the larger turbine model used for the latest estimate.[34]

The Package 13 alternative set of triennial review changes that received the most stakeholder support adopts the CONE values set forth in the table above, but would eliminate the Tariff's current Handy-Whitman index adjustment method. Alternatively, Package 13 would keep the Handy-Whitman adjustments, but base the 2015-16 Delivery Year CONE values on the "real levelized" financial model, rather than the "nominal levelized" approach.[35]

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34 2011 CONE Study at 2.

35 As explained by the Commission earlier this year, the real levelized approach:

> produces lower numbers in the early years of a project's life and higher numbers in the later years [compared to nominal levelized], by assuming that plant revenue requirements will increase each year to reflect a 2.5 percent annual increase in operating expenses.

(continued…)

In its sole departure from Package 13, PJM is not changing either of these current practices. As with each prior Commission-accepted CONE estimate, PJM is basing the latest CONE values on the nominal levelized approach. Nor is PJM proposing any change to the Handy-Whitman index adjustment approach that the Commission approved two years ago.

The Commission has consistently accepted use of the nominal levelized approach in RPM as just and reasonable, and has rejected attempts to compel PJM to base generic CONE values (such as those used in the VRR Curve) on the real levelized basis.[36] Indeed, the Commission reaffirmed just two weeks ago that "the nominal levelized method is a just and reasonable method of modeling a competitive bid, in part because it is a reasonable method of modeling a competitive first-year offer based upon typical cash flow streams associated with financing" and is consistent with "the mortgage-like cash stream associated with project finance."[37]

Moreover, although Brattle recommends in the RPM Performance Assessment that PJM and its stakeholders "consider transitioning" to a real levelized approach for CONE, Brattle's recommendation is expressly conditioned on PJM's adoption of Brattle's recommended changes to the EAS calculation method.[38] But PJM is not adopting Brattle's recommended change to a projected EAS calculation based on PJM future market simulations or forward fuel and power indices. Nor did Package 13 propose to change the EAS method to one based on such simulations or forward indices.

Moreover, as explained by Dr. Paul M. Sotkiewicz in his affidavit, Brattle's assumption of a steady-state condition in which risk-neutral project developers confidently anticipate regular annual increases in their revenues at the inflation rate does not account for either the real world risks and uncertainties that can cause project developers to hold back on their investments if they are not assured of a satisfactory revenue stream. Simply put, the Commission was correct to affirm just two weeks ago that a real levelized approach is problematic in a generic CONE calculation, and the Brattle observations do not provide a compelling reason for the Commission to make a sudden and dramatic reversal on that issue.

(…continued)

PJM Interconnection, L.L.C., 135 FERC ¶ 61,022, at P 34, n.28 (2011).

36 *Id.*, 135 FERC ¶ 61,022, at PP 49-51.

37 *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 32 (2011) (*"MOPR Rehearing Order"*).

38 RPM Performance Assessment at 85.

Nor is there any basis for striking the Handy-Whitman index adjustment from the Tariff. Brattle did not recommend this change, and the Handy-Whitman index approach is not incompatible with use of a nominal levelized model. The Commission accepted the Handy-Whitman approach in the *October 2009 RPM Order* even though the CONE update that the Commission approved earlier that year was based on a nominal levelized analysis. As the Commission found in accepting the Handy-Whitman index approach, basing CONE values "upon a known and unbiased formula" can help "market participants . . . gain a higher degree of certainty regarding forecasted CONE values" which should "facilitate capacity market stability that will foster the locational construction of new resources and promote conditions conducive to long-term contracts for capacity resources."[39]

Accordingly, PJM is revising the Tariff to adopt for the 2015-16 Delivery Year the CONE values set forth in the table above.

4. RTO Region Price.

The 2011 CONE Study did not specify a CONE value for the PJM Region as a whole. Such a value is needed, however, to construct a VRR Curve representative of the entire PJM footprint. In this filing, PJM adopts the Package 13 approach, favored by most stakeholders, of setting a Net CONE for the PJM Region equal to the median of the Net CONE values calculated for the five CONE Areas.

This approach is reasonable. The Tariff currently requires PJM to calculate an EAS offset for the PJM Region based on system-average LMPs,[40] so PJM's previously approved practice already uses a measure of central tendency in the region-wide Net CONE calculation. The stated *gross* CONE value for the PJM Region now in the Tariff corresponds to the lowest gross CONE value for any CONE Area, but nothing in the Tariff or in any Commission order requires PJM to base the region-wide gross CONE on the lowest CONE Area CONE value. Using the lowest gross CONE value from the CONE Areas in the current circumstances would be unreasonable. The lowest value shown above (i.e., the CONE Area 5 value) differs materially from the others because it does not include SCR. Therefore, that value is unreasonably low relative to the rest of the PJM Region where state or federal environmental rules indicate the need for SCR technology to reduce emissionsNO_x that lead to the formation of ozone. By contrast, using the median Net CONE will eliminate any extreme Net CONE observations, and as a measure of central tendency is consistent with the current effective practice of using the system-average LMPs in the EAS calculation. Therefore, using the median Net CONE will make the PJM Region price more representative of pricing throughout the PJM footprint.

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39 *October 2009 RPM Order* at P 38.

40 Tariff, Attachment DD, section 5.10(a)(vi) (eTariff record OATT Attachment DD.5.10).

To effectuate this Package 13 element, PJM is eliminating the value currently referenced in the Tariff as the CONE for the PJM Region, deleting the language that describes how to calculate an EAS estimate for the PJM Region, and adding language that directs PJM to adopt as the PJM Region Net CONE the median value of the Net CONEs calculated for the CONE Areas. This change also requires PJM to move from section 5.10(a)(v)(B) to section 5.10(a)(v)(A) existing text that describes how to perform the EAS calculation for the CONE Areas.

PJM also is clarifying in the Tariff that, to the extent a gross CONE value is needed for the PJM Region,[41] it will be the gross CONE component of the CONE Area that has the median Net CONE.

C. Revision to Net EAS Revenue Offset Methodology.

1. Background.

The current Tariff directs PJM to estimate the energy revenues that the Reference Resource would receive based on actual LMPs and fuel prices for the most recent three calendar years, the heat rate of the Reference Resource, and an assumption that the resource would be dispatched on a "Peak Hour Dispatch" basis. The Tariff defines Peak Hour Dispatch in terms of real-time LMPs;[42] it does not consider LMPs in the Day-ahead Energy Market. Indeed, the current method implicitly assumes that a capacity resource like the Reference Resource is *never* committed in the Day-ahead Energy Market.

In the proceedings earlier this year on the MOPR, some parties objected to use of a real-time-only dispatch assumption for the MOPR screen value, noting that the assumption was particularly inappropriate for the combined-cycle plants to which MOPR might apply. In a request for clarification on that issue, PJM committed to explore it further in a stakeholder process this year. In response, the Commission clarified that it did not intend to preclude parties from pursuing issues such as "the use of day-ahead prices for calculating energy and ancillary service offsets."[43] Indeed, the Commission added, in response to the separate rehearing requests on the merits of using only real-time LMPs, that "other methodologies could be used to estimate energy and ancillary services

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41 Gross CONE has little application outside its use in calculating Net CONE. One area, however, in which a gross CONE value will be used is the proposed calculation, described above, of point 1 on the VRR Curve as the greater of gross CONE or 1.5 times Net CONE.

42 Tariff, Attachment DD, section 2.46 (eTariff record OATT Attachment DD.2)..

43 *MOPR Rehearing Order* at P 34.

revenue for CT and CC units based upon the actual unit commitment process (and PJM may wish to examine such methods)."[44]

The stakeholders discussed this issue for several months, both in the context of the MOPR and the VRR Curve. Brattle noted this same issue in the RPM Performance Assessment, observing that "the peak-hour dispatch methodology only uses real-time prices, which is not consistent with the fact that the majority [of] revenues are obtained through day-ahead commitments, even for CTs."[45] The report noted that not only do "CC plants earn most of their revenues in the day-ahead market," but "even new CT plants similar to the reference technology earn only approximately 40% of their energy revenues in the [real-time] market, compared to 100% assumed in the current dispatch methodology."[46] The RPM Performance Assessment therefore recommended that "the dispatch logic should attempt to replicate realistic participation in both the day-ahead and real-time energy markets."[47]

Upon issuance of the RPM Performance Assessment, PJM recommended modifying the EAS methodology to reflect commitment of the Reference Resource in the Day-ahead Energy Market to the extent economic on a Peak-Hour dispatch basis. The stakeholders' Package 13 alternative also included this same EAS change in its triennial review recommendations. Accordingly, PJM proposes such a change in this filing.

Brattle also recommends in the RPM Performance Assessment that PJM and its stakeholders "continue to consider" the possibility of developing "acceptable forward-looking or equilibrium-based methodologies to determine the E&AS offset."[48] Brattle bases its recommendation on shortcomings that it identifies in the current estimating approach that relies on historic data. But Brattle recognizes that PJM, stakeholders, and the Commission have previously rejected both of Brattle's suggested alternative approaches, i.e., future market simulations and price forecasts by PJM, and complex forecasts based on forward prices for fuel and power.

PJM understands the concerns Brattle has raised with the historic EAS estimating method, but does not believe there is a compelling need for a dramatic change in the EAS estimating method at this time. PJM notes that none of the stakeholder-developed alternative package approaches to the triennial review presented to the Members Committee included a new forward-looking EAS estimating method. The change

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44 *Id.* at P 31.

45 RPM Performance Assessment at 88.

46 *Id.*, citing the PJM Region Independent Market Monitor's September 29, 2009 analysis "CT Revenues: Day-Ahead vs. Real-Time."

47 *Id.*

48 *Id.* at 91.

adopted here, to add consideration of day-ahead prices, should improve the accuracy of the historic method, and is not intended to foreclose any future attempts to develop forward-looking estimating methods that are shown to be transparent, reproducible, and reliably more accurate than current methods.

2. Proposed Tariff Change.

PJM is revising the Peak-Hour Dispatch definition in the Tariff to provide that the Reference Resource will be committed first in the Day-ahead Energy Market if economic on a peak-hour basis. The revised definition provides that, to the extent not committed in the Day-ahead Energy Market, the Reference Resource will be dispatched in the Real-time Energy Market if economic on a peak-hour basis. PJM is not proposing any other change to the mechanics or details of the peak-hour test; rather PJM is simply proposing to apply that test in both the day-ahead and real-time markets. Under this approach, there is no pre-determined split between the day-ahead and real-time markets. Whether and the extent to which the Reference Resource is committed in the Day-ahead and/or Real-time Energy Markets will be determined by whether the plant is economic over the given hourly blocks, based on its assumed heat rate, historic fuel prices, historic day-ahead LMPs, and historic real-time LMPs.

III. TARIFF CHANGE RESULTING FROM PERFORMANCE ASSESSMENT.

A. Background.

The 2006 settlement that established RPM included a requirement, embodied in the Tariff, that "[w]ithin six months after the end of the fourth Delivery Year, the Office of the Interconnection shall prepare, provide to Members, and file with FERC an assessment of the performance of the Reliability Pricing Model."[49]

RPM was approved in December 2006, with the first BRA held in May 2007 and the first RPM Delivery Year extending from June 1, 2007 to May 31, 2008. The fourth Delivery Year began on June 1, 2010 and ended on May 31, 2011.

PJM retained Brattle to conduct the required performance assessment. Brattle considered not only the four Delivery Years that have been completed to date, but also the performance of RPM reflected in auctions conducted for Delivery Years through May 31, 2015, "to assess RPM's effectiveness in encouraging and sustaining sufficient capacity investments for reliability."[50] Brattle also conducted stakeholder interviews to identify key areas of concern; evaluated individual design elements of RPM (such as the

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49 Tariff, Attachment DD, section 17.6.

50 RPM Performance Assessment at i.

VRR Curve and EAS offset methodology, as discussed above); and performed a probabilistic simulation analysis of RPM's performance.[51]

B. Brattle's Report.

Brattle completed its report in August 2011, and PJM posted the report to its website. In fulfillment of its obligations under section 17.6 of the Tariff, PJM herewith presents Brattle's report, i.e., the RPM Performance Assessment, to the Commission.[52]

The report's primary finding is that "RPM is performing well."[53] More specifically, the RPM Performance Assessment's key findings are that:

- RPM has attracted and retained sufficient capacity to maintain resource adequacy in the RTO and in all LDAs, in spite of environmental and other challenges faced by suppliers.
- Since RPM was implemented, a total of 28,400 MW of installed capacity from new resources have been committed, including additions of 11,800 MW of demand side resources, 6,900 MW of increased imports and decreased exports, and 4,800 MW of new generation.
- In all LDAs, net resource additions have been more than sufficient to meet reliability requirements.
- RPM has greatly facilitated competition among various types of capacity resources, attracting commitments from new generation and new DR resources, retaining existing generation, and supporting the upgrade of existing plants at prices below the cost of new generation.
- Competition in RPM's centralized forward auctions has also allowed owners of aging coal plants to make more informed decisions about whether to invest in environmental retrofits or start planning to retire the units, particularly in the most recent auction for the 2014-15 Delivery Year.
- As a result of offers from a wide variety of new resources, particularly demand response resources, the BRA supply curves have become smoother and less steep over time, mitigating the steep offer curves in the first few auctions, increasing competition between resources in the recent auctions and reducing price volatility going forward.
- BRA prices have been consistent with the supply and demand for capacity, with prices volatile due to market fundamentals, but below Net CONE after the

51 *Id.*

52 Brattle made some minor corrections to the report after it was first posted in August. The attached copy reflects all such corrections and edits made by Brattle; all of which have previously been posted on PJM's website.

53 RPM Performance Assessment at i.

transition period, reflecting that new generation was not needed to maintain resource adequacy given the availability of lower-cost alternatives.

- Clearing prices in the incremental auctions have been persistently below BRA prices, in part reflecting low incremental demand for capacity due to declines in load forecast and increased transmission capabilities.

Notwithstanding the overall favorable findings, Brattle also made several recommendations for changes to further enhance RPM's performance in sustaining and attracting investment to ensure PJM has sufficient capacity resources to meet resource adequacy and reliability objectives, as discussed below.

C. Stakeholder Process.

Following the posting of the RPM Performance Assessment in August 2011, PJM facilitated a stakeholder process to consider possible Tariff or business rule changes in light of Brattle's findings and recommendations. Some of Brattle's key recommended Tariff changes in the RPM Performance Assessment related to the triennial review items, i.e., the VRR Curve shape, selection of the Reference Resource, CONE and the EAS estimating method. Those items were considered on a slightly different track by the stakeholders to meet the Tariff-prescribed deadlines for the triennial review, and are discussed in the prior sections of this transmittal.

Aside from the triennial review items, Brattle also recommended a few other changes. While the stakeholders considered those recommendations, none of Brattle's suggested changes that would necessitate a Tariff amendment received the two-thirds (sector-weighted) vote required for formal endorsement by the Members Committee.

Of those other Brattle recommendations, PJM is electing to adopt one at this time and thus submits herewith the required section 205 Tariff change. That change, i.e., retaining the overall 2.5 percent Short-Term Resource Procurement Target ("STRPT") or load "hold-back" but eliminating the subsidiary hold-backs that apply only to the minimum requirements for two resource categories, is discussed below. PJM believes that some of the other Brattle recommendations may have merit and would enhance RPM's performance but more stakeholder discussion is required to consider these recommendations. Therefore, PJM will invite further stakeholder consideration of the additional Brattle recommendations which may result in additional Tariff revisions in subsequent filings.

D. Elimination of "Hold-Back" From the Minimum Requirements for Certain Types of Capacity Resources.

1. Background.

In the *March 2009 RPM Order*, the Commission approved PJM's proposed elimination from RPM (effective with the 2012-13 Delivery Year) of Interruptible Load for Reliability ("ILR"), which was a form of demand response that did not have to commit in the forward auctions but instead could wait until just before the start of the Delivery Year to commit to PJM, while still receiving essentially the same economic benefits as Demand Resources that commit three years forward.[54] To mitigate some of the impact of eliminating ILR, the Commission approved new Tariff provisions that effectively defer to the Incremental Auctions a portion of the resources otherwise targeted for procurement in the BRA. This adjustment, known as the STRPT[55] or "hold-back," reduces the Reliability Requirement that is targeted for procurement in the BRA, and then adds that reduction to the quantities that PJM seeks to procure in the Incremental Auctions. Since the Incremental Auctions range from two years to four months before the Delivery Year, this deferral helps ensure that capacity sellers that are not able to commit their resources three years in advance have an opportunity to commit to PJM closer to the Delivery Year. Indeed, the Commission went even further than PJM on this issue. PJM proposed to recoup an equal one-third share of the hold-back in each of the three Incremental Auctions, but the Commission ordered PJM instead to overweight the recovery towards the Third (and final) Incremental Auction, and thereby "allow greater participation, as close as possible to the Delivery Year, of short lead time resources."[56]

Earlier this year, the Commission approved Tariff changes proposed by PJM to establish multiple types of Demand Resource products as a market-based approach to addressing reliability concerns about possible over-reliance on PJM's pre-existing Demand Resource product that has strict limits on its availability.[57] Specifically, the long-standing Demand Resource product that need be available only ten times over a three-month summer season, for no more than six hours at a time, was renamed Limited Demand Resources, but otherwise unchanged. PJM added two new products known as Annual Resources, that are available year-round, and Extended Summer Demand Resources, that are available an unlimited number of times over a five-month "extended" summer season. Annual Resources can include any type of resource, i.e., generation, energy efficiency, or demand response, so long as it is available year-round.

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54 *March 2009 RPM Order* at P 83.

55 *See* Tariff, Attachment DD, section 2.65A (eTariff Record OATT Attachment DD.2).

56 *March 2009 RPM Order* at P 84.

57 *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066 (2011).

Rather than eliminate Limited Demand Resources, or impose hard ceilings on the commitment level for Limited Demand Resources, PJM proposed, and the Commission approved, setting minimum requirements for Annual Resources, and for the sum of Annual and Extended Summer Resources, and allowing price separation, i.e., higher compensation for higher-valued products, when one or both of those minimum requirements are not satisfied. Indeed, the Commission expressly rejected calls for elimination or phase-out of Limited Demand Resources, agreeing with PJM that there was no evidence that "the current demand resource product [is] unjust and unreasonable," only that PJM "must not place over-reliance on this product, given the limits on when it is required to respond."[58] Thus, while the new rules can, in operation, produce price incentives that may lead to a natural development of more resources that have fewer limits on their availability, PJM has strenuously avoided Tariff changes that would raise barriers to entry by Limited Demand Resources, or any by other types of Demand Resources.

As part of the rules establishing the two new Demand Resource products, PJM proposed to apply the hold-back to the minimum requirements for the two new products, as well as applying them to the overall load level of all resources that are targeted for procurement in the BRA. More specifically, PJM subtracts the STRPT from both the Minimum Annual Resource Requirement[59] and the Extended Summer Resource Requirement.[60] To be clear, these rules establish "layered" requirements—first a minimum amount of Annual Resources; second, on top of the first layer, a minimum requirement for the sum of Annual Resources and Extended Summer Resources; and third, on top of the two previous layers, an overall resource requirement. The full hold-back, not a prorated share, is subtracted from *each* of these "layers." The rationale for this change in the hold-back was not extensively discussed in PJM's initial filing in that proceeding (PJM offered it simply as a corresponding reduction to preserve the overall hold-back) and has been in effect for only one auction—the May 2011 BRA for the 2014-15 Delivery Year.

In the 2014-15 BRA, PJM cleared a substantial quantity of Demand Resources, primarily as Limited Demand Resources. Specifically, the BRA cleared 12,166 MW of Limited DR, 1,441 MW of Extended Summer Demand Resources, and 512 MW of

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58 *Id.* at P 32.

59 The Minimum Annual Resource Requirement is the amount of Annual Resources, i.e., generation or Demand Resources, or energy efficiency resources, that are available year-round, targeted for procurement in the BRA.

60 The Extended Summer Resource Requirement is the amount of Extended Summer Resources, i.e., Demand Resources that are available for more hours of the day, and more days of the year than traditional Limited Demand Resources, targeted for procurement in the BRA.

Demand Resources that qualified as Annual Resources.[61] Prices separated for the product types in that auction. In order to meet the minimum requirement for the combination of Annual and Extended Summer Resources, PJM had to clear higher-priced offers for those two resource types. But PJM paid that price premium only until it cleared the required minimum quantity for those two resource types, and did not clear any more of those higher-priced resources after it satisfied the minimum.

2. The Recent Revisions to the Hold-back Can Operate To Limit Participation by Short Lead Time Resources in the Incremental Actions, Contrary to the Hold-back's Original Purpose.

Brattle reviewed these new hold-back rules in the RPM Performance Assessment and concluded that "[t]he result of this approach is that the STRPT quantity held back is Annual capacity, which means the resources procured in the incremental auctions for the 2014/15 Delivery Year will be primarily for Annual capacity."[62] Brattle's point is well-taken and highlights some significant adverse unintended consequences of the recently implemented changes to the hold-back rules.

As Dr. Sotkiewicz shows in his affidavit, the minimum requirements in the May 2011 BRA for Annual Resources was 128,450 MW, for the sum of Extended Summer and for Annual Resources was 137,809 MW, and for all resources (i.e., the overall Reliability Requirement) was 144,615 MW. These values reflect a reduction in each case by the calculated hold-back quantity of 3,708 MW, which, per the current Tariff as explained above, is subtracted from each of these "layered" requirements. The BRA cleared enough Annual Resources to satisfy the Annual Resource Requirement without price separation, but, as noted above, had to pay higher prices to clear enough combined Annual and Extended Summer Resources to meet the minimum requirement for those combined resources, and stopped procuring those higher-priced resource types as soon as it satisfied that minimum. The difference between that combined minimum Annual and Extended Summer Resource requirement, 137,809 MW, and the total resource quantity cleared in the BRA, 149,975 MW, reflects the amount of Limited Demand Resources cleared in the BRA, i.e., 12,166 MW as noted earlier.

As Dr. Sotkiewicz explains in his affidavit, in the three Incremental Auctions for the 2014-15 Delivery Year, the overall hold-back of 3,708 MW must come entirely from Annual or Extended Summer Resources (assuming no change in the Reliability Requirement from the BRA to the Incremental Auctions), because the overall hold-back of 3,708 MW equals the hold-back from the combined minimum Annual and Extended

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61 *See* PJM's report on the May 2011 BRA ("2014-15 BRA Reporrt"), at page 7, available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base -residual-auction-reportt.ashx

62 RPM Performance Assessment at 143.

Summer Resource requirement of 3,708 MW. As explained above, PJM stopped procuring those resources in the BRA as soon as it hit the minimum for those combined resources—which in the BRA was reduced by the full amount of the hold-back: 3,708 MW.

Therefore, under the current rules, absent an increase in the overall Reliability Requirement,[63] Limited Demand Resources will not be eligible to meet the hold-back capacity that PJM will seek to procure for the region in the Incremental Auctions. Either Annual Resources or Extended Summer Resources can be used to recoup that hold-back in the Incremental Auctions, but Limited Demand Resources cannot. As Dr. Sotkiewicz observes, "Limited DR might as well not even participate in the IAs (under this scenario) because they cannot be selected to clear."[64]

In other words, the current rules can foreclose the very opportunity that the Commission approved the hold-back to address, i.e., the opportunity for short-lead time resources (that may not be able to commit three years forward) to participate in RPM auctions closer to the Delivery Year. Under the current rules, Limited Demand Resources cannot be selected in the Incremental Auctions to satisfy the deferred hold-back quantity in the very first year these rules have been applied. Foreclosing Limited Demand Resources from the Incremental Auctions closes off the opportunity to commit closer to the Delivery Year for the largest single source of short lead time resources. Limited Demand Resources comprised the largest category of Demand Resources offered in the BRA for the 2014-15 Delivery Year, and was the largest category of Demand Resources cleared in that BRA. Moreover, as discussed below, this rule also can, under some circumstances, foreclose Extended Summer Resources from being used to satisfy the hold-back in the Incremental Auctions.

The 2014-15 Delivery Year is not likely to be anomalous if the current rules are maintained. *Every* BRA in which *either* the Minimum Annual Resource Requirement *or* the minimum requirement for the combined Annual and Extended Summer Resources binds will follow the same pattern. The BRA will procure only the minimum quantity for that resource type assigned to the BRA. It will not procure above the minimum, because that resource type will have price-separated, and the auction-clearing mechanism will not pay an elevated price to procure any more than the minimum quantity needed for that resource type. This means that the full amount of the hold-back for that resource type

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63 If the Reliability Requirement increases by a threshold amount from the BRA to the Incremental Auctions, the auction will seek to obtain offers from any type of resource to satisfy that increased need for capacity. *See* Tariff, Attachment DD, sections 5.4(c) and 5.12(a) – (b).

64 Sotkiewicz Affidavit at Paragraph 24.

will need to be procured in the Incremental Auctions;[65] which in turn means that more limited resources will not be selected in the Incremental Auctions to recoup the hold-back.[66] If the Annual Resource constraint binds in the BRA, only Annual Resources will be selected in the Incremental Auctions to recoup the hold-back. Neither Extended Summer Resources nor Limited Demand Resources could be selected to recoup the hold-back in that scenario. Similarly, if the constraint for the combined Annual and Extended Summer Resources binds (as it did in the last BRA), only those two resource types would be selected to recoup the hold-back in the Incremental Auctions; Limited Demand Resources would not be selected.

In short, the hold-back rules that were put into effect earlier this year are having, and likely will continue to have, an unintended effect of defeating much of the purpose for which the hold-back was introduced, i.e., ensuring short lead time resources a reasonable opportunity to commit in an RPM auction closer to the Delivery Year.

The Tariff changes in this filing, as described below, will correct these unintended consequences and restore to short lead time resources the flexibility to participate in the Incremental Auctions, as the Commission intended when it approved the hold-back. As explained by Dr. Sotkiewicz, by removing the hold-back from the Minimum Annual Resource Requirement and Minimum Extended Summer Resource Requirement in the BRA, PJM will eliminate the possibility that it will be allowed to seek only Annual Resources in the Incremental Auctions (if the Annual Resource constraint binds in the BRA), or allowed to seek only a combination of Annual and Extended Summer Resources in the Incremental Auctions (if the combined Annual-Extended Summer Resource constraint binds in the BRA). This in turn eliminates the possibility that PJM will be precluded from selecting Limited Demand Resources (or in some cases, precluded from selecting Extended Summer Demand Resources) in the Incremental Auctions to recoup the hold-back.

The Tariff revisions in this filing will restore the ability for all types of Demand Resources to participate in the Incremental Auctions, and thus preserve the hold-back's purpose of ensuring commitment opportunities closer to the Delivery Year for short lead time resources. It will remove the unintended barriers created by the hold-back changes implemented earlier this year to Incremental Auction participation by Limited Demand

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65 Per the Tariff, Attachment DD, section 5.12(b)(v), PJM will take into account the quantities of Annual or Extended Summer Resources that clear the BRA when determining what to procure in the Incremental Auctions, but if either constraint binds in the BRA, and PJM procures in the BRA no more than the minimum (less the hold-back) for that resource type in the BRA, that leaves PJM required to seek the full hold-back in the Incremental Auctions in the form of that resource type.

66 Such resources would only be selected if needed to satisfy a separate requirement to meet an increased Reliability Requirement.

Resources and, potentially, Extended Summer Demand Resources. And since the Tariff changes in this filing fully preserves the overall hold-back, all types of Demand Resources—Annual, Extended Summer, or Limited Demand Resources —will still be able to compete to satisfy the deferred hold-back quantity in the Incremental Auctions, if they need that to implement their short lead time business model. Even if PJM is not *obliged* to procure additional Annual or Extended Summer Resources in the Incremental Auctions, as can happen under the current rule, those resource types still can offer in the Incremental Auctions, and the overall hold-back ensures that there will be a supplemental procurement of resources closer to the Delivery Year to meet the PJM Region's overall needs for resources for the Delivery Year.

This filing also preserves flexibility for all types of Demand Resources to participate in the BRA. By eliminating the hold-back from the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement, Annual Resources, including Annual Demand Resources, and Extended Summer Demand Resources will have increased opportunities to clear in the BRA. And Limited Demand Resources still will have ample opportunities to commit as PJM capacity in the BRA. In the BRA, the overall Reliability Requirement is a milestone or target, not a stopping point. The BRAs often procure more than the Reliability Requirement, as happened in the last BRA. Indeed, in the last BRA, since the Minimum Extended Summer Resource Requirement constraint bound, effectively the entire commitment above that level consisted of Limited Demand Resources. This resource commitment above the Reliability Requirement underscores the fundamental point that commitment of Limited Demand Resources in the BRA *is a function of price*. Since the RPM auctions clear above the Reliability Requirement only when it is economic to do so, Limited Demand Resource suppliers can increase their chances of being committed in the BRA by offering at an economic price. In addition, as the Commission expressly recognized when approving the new Demand Resource product categories, Demand Resource providers can aggregate end-use customers that might individually qualify only as Limited Demand Resources into resources that in combination meet the standards for Extended Summer or Annual Demand Resources.[67] Indeed, prospective capacity market sellers demonstrated in the last BRA that they can qualify a substantial part of their reduction capability as Annual or Extended Summer Resources. Over half of the Demand Resource quantities offered were "coupled" offers (as described by Dr. Sotkiewicz) that could qualify as either Limited Demand Resources or as one or more of the other, less limited, resource types.[68]

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67 *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066, at P 32 (2011).

68 See 2014-15 BRA Report at 7.

3. <u>The Current Hold-back Rules Create Needless Uncertainty for Longer Lead Time Annual Resources That the Hold-back Was Never Intended to Address.</u>

As shown above, the revised hold-back rules implemented earlier this year can skew the hold-back's resource procurement deferral towards Annual Resources. But Annual Resources overwhelmingly consist of generation resources, and generation resources do not have short lead times for their development. Of most immediate concern to the PJM Region, generation owners considering whether to invest in emissions control retrofits or other capital improvements to keep certain of their generators in service need ample time to permit and install those improvements, and the Incremental Auctions likely do not provide enough time to suit that purpose. Certainly, the Third Incremental Auction, to which recoupment of the hold-back is heavily weighted, and which is held only four months before the Delivery Year, is wholly inadequate to that purpose. This example simply underscores the fact that the hold-back—designed to mitigate the impact of the elimination of "Interruptible Load for Reliability," was never intended to defer procurement of generation resources. But the recently implemented hold-back changes likely will have exactly that effect.

4. <u>As Brattle Found, the Current Hold-back Rules Can Suppress Prices in the BRA for Annual Resources (Including Annual Demand Resources) and Extended Summer Demand Resources.</u>

In addition to noting the current rule's skewing of the hold-back's deferral toward the Annual Resource category, Brattle also found in the RPM Performance Assessment that the current hold-back rules could suppress prices in the BRA for both Annual and Extended Summer Resources. Brattle found that the overall hold-back was unlikely to suppress prices, but that the hold-back from the minimum Annual and Extended Summer Resource Requirements could have that effect. Brattle therefore recommended that PJM retain the overall hold-back, but stop subtracting it from the category-specific minimum requirements.

To analyze this question, Brattle considered the extent to which sellers in the various resource categories had flexibility to choose not to participate in the BRA and seek potentially higher prices in the Incremental Auctions. Specifically, Brattle compared the megawatt quantities of the overall hold-back for the region as a whole, for Annual Resources, and for Extended Summer Resources, against the quantities of capacity overall, and in each of those resource categories, that is not subject to a requirement that it must offer in the BRA, and that is not subject to offer price mitigation. Brattle found that, overall, the amount of capacity not subject to a must-offer or offer-price mitigation requirement exceeded the overall hold-back, indicating that the overall hold-back was not likely to distort prices (since it was less than the quantity of capacity that in any event had the freedom to choose to offer into the Incremental Auctions rather than into the BRA). Brattle's analysis of this issue does not depend on the relative price level, historically or projected, between the BRAs and the Incremental Auctions. Their focus was instead on the extent to which suppliers have the flexibility to exercise an economic choice to offer into the BRA at their desired price, or sit out the BRA and instead offer their desired price in the Incremental Auctions. Brattle's observations about the market power mitigation constraints on that flexibility apply regardless of clearing price levels in the BRA or Incremental Auctions.

For both the specific resource categories, Brattle found that the quantity of capacity not subject to a must-offer or offer-price-cap requirement was significantly less than the hold-back quantity. In the case of Annual Resources, for example, this means that sellers of those resources do not have the flexibility to shift their capacity from the BRA to the Incremental Auctions in a quantity that matches the hold-back quantity for those resources. Given these constraints, Brattle found that forcing procurement of part of the minimum required Annual Resources out of the BRA and into the Incremental Auctions simply distorts prices in the BRA. Since this rule can distort price for Annual Resources, this necessarily means that it can distort prices for Annual Demand Resources and Energy Efficiency Resources. Brattle found the same disadvantageous mismatch between the extent of resource provider flexibility and the level of the hold-back quantity for Extended Summer Demand Resources. Therefore, the potential price suppression that Brattle found is a serious concern not only for generation, but also for Demand Resources and Energy Efficiency Resources.

In sum, the RPM Performance Assessment found that the overall hold-back "does not distort capacity prices because more than 2.5% of total resources offered are unmitigated, allowing suppliers to freely adjust their offers or their decisions to participate in BRAs versus incremental auctions."[69] By contrast, "[h]olding back procurement of 2.5% of these higher-quality [Annual and Extended Summer] resources could suppress prices."[70] As Brattle explained, eliminating the hold-back for Annual Resources, which mostly are generation, will "also add a safeguard to reduce the risk of resource adequacy challenges in the face of retirement pressures on existing coal plants from new EPA regulations" given that full procurement of Annual Resources "will reduce the risk that existing resources do not clear due to artificially suppressed BRA prices, which could lead to inefficient retirements of resources that may not be replaceable in the short term."[71] Moreover, Brattle found that eliminating the hold-back

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69 RPM Performance Assessment at ix.

70 *Id.*.

71 Id. at 147. *See also* United States Environmental Protection Agency 2003 Technical Support Package for Clear Skies, Section G: Factors Affecting the Installation of Pollution Control Technologies available at http://www.epa.gov/air/clearskies/03technical_package_sectiong.pdf. It is estimated that the installation of controls on existing coal units takes 27 months for wet limestone scrubbers and 21 months for selective catalytic reduction.

for these resource categories "will not substantially disadvantage short lead-time resources, because DR accounts for most short lead-time supplies, few of which have cleared as Annual or Extended Summer supplies."[72]

In the RPM Performance Assessment therefore, Brattle recommended that PJM retain the overall 2.5% hold-back, but eliminate any hold-back for Extended Summer and Annual Resources.

5. Proposed Tariff Change.

PJM is revising the Tariff to implement Brattle's recommended change on this issue. PJM agrees with Brattle that the effect of the hold-back changes approved earlier this year focuses the hold-back on Annual Resources, very few of which are the short-term resources that were the intended focus of the hold-back. PJM also agrees with Brattle that holding back Annual Resources from the BRA under the market power mitigation conditions applicable to the vast majority of Annual Resources makes it likely that the hold-back leads to inefficient price distortions and price suppression, and that it is especially important at this time to send correct price signals to generation resources that may be considering their retirement options in light of forthcoming EPA regulations affecting the industry.[73]

Accordingly, PJM is revising the Tariff's definitions of both the Minimum Annual Resource Requirement[74] and the Minimum Extended Summer Resource Requirement[75] to remove the clause that requires subtraction of the STRPT from the calculation of those quantities for both the PJM Region as a whole and any relevant LDAs.

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72 RPM Performance Assessment at 147.

73 There is a considerable amount of coal-fired capacity in the PJM Region that requires pollution control retrofits to continue operations in the future due to the EPA-promulgated CSAPR and NESHAP rules. *See* Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standard for Hazardous Air Pollutants, August 26, 2011 available at http://www.pjm.com/documents/~/media/documents/reports/20110826-coal-capacity-at-risk-for-retirement.ashx

74 Tariff, Attachment DD, section 2.41D (eTariff record OATT Attachment DD.2).

75 *Id.*, section 2.41E (eTariff record OATT Attachment DD.2).

D. Non-Tariff Changes Approved By Stakeholders.

The RPM Performance Assessment also recommended several changes that, while important to PJM and stakeholders, do not require Tariff changes. The Members Committee endorsed these Performance Assessment-related changes at its last meeting with a two-thirds supermajority (sector-weighted) vote in favor

Accordingly, to implement the relevant Brattle recommendations, PJM has committed to provide stakeholders the following additional information::

- Capacity Emergency Transfer Limits ("CETLs") for LDAs (in a similar manner to the CETL calculations now performed for the RPM auction parameter postings) as part of the 5-year-forward baseline analysis in the regional transmission expansion planning process;
- identification of successive limiting elements for each LDA (unless there is a large margin between CETL and the Capacity Emergency Transfer Objective), assuming no change in the impedance of the network model to calculate the next limiting facility; and
- a semi-annual load forecast update for zonal coincident peaks based on the latest economic projections.

The PJM stakeholder process on planning issues is also considering changes that would further address some of the planning-related recommendations in the RPM Performance Assessment.

IV. RELATED AND CONFORMING CHANGES.

A. NEPA Clarifications.

A two-thirds supermajority of PJM stakeholders concluded that the existing NEPA should be retained for the present with no substantive changes. They did agree, however, that the language of the current NEPA provision could be clarified to eliminate possible ambiguity in its application. The enclosed changes to the NEPA provision[76] serve this purpose, making references more explicit, using more precise language, and ensuring greater internal consistency among the NEPA provisions.

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[76] *Id.*, section 5.14(c) (eTariff record OATT Attachment DD.5.14).

Specifically, the enclosed NEPA changes:

- Clarify that to be eligible for NEPA treatment, a new entry resource must be the marginal offer that sets the clearing price in the first BRA;
- Use more consistent language to recognize the possibility of minimum block quantities and more clearly describe their treatment in the first and subsequent Delivery Years;
- More precisely describe the capacity level on the VRR Curve to which the NEPA sell offer must move the clearing point;
- Clarify that the NEPA plant's sell offers in subsequent years must be at the lesser of its sell offer in the first year or 90% of the Net CONE in that first year;
- Confirms that the NEPA plant's failure to submit a sell offer in the second year that complies with the relevant NEPA conditions prevents the seller from seeking the NEPA for that resource in the third year; and
- Divides the NEPA provision into additional numbered subsections for greater clarity and ease of reference.

As administrator of the Tariff, PJM views these changes as simply confirming the existing intent of the NEPA provision and the manner in which PJM has applied or would apply NEPA under the various scenarios that might arise for a NEPA resource. As such, these changes are just and reasonable.

B. Date Certain to File Voluntary Long-Term Auction Provisions.

In the MOPR proceeding, PJM advised the Commission that a number of parties, including state commissions, project developers, and members of the investment community, had expressed to PJM concerns about whether the current NEPA provision is providing adequate incentives for the addition of new capacity to the PJM Region. Recognizing the importance of this issue, PJM proposed to add to its Tariff a date certain for PJM to conclude a stakeholder process on possible NEPA changes and file any resulting Tariff changes deemed necessary by PJM. PJM was cognizant, however, of the concerns expressed by the Commission in the *March 2009 RPM Order* that changes to NEPA should not result in undue discrimination between old and new resources.

PJM therefore proposed to add to the NEPA provision a new subsection requiring that "[o]n or before October 1, 2011, PJM shall file with FERC under FPA section 205 revisions to [NEPA] as determined necessary by PJM following a stakeholder process."[77] PJM added that any such change would be intended "to address concerns expressed by

[77] *Id.* at section 5.14(c)(8) (eTariff record OATT Attachment DD.5.14).

some parties that [the current NEPA] may not provide adequate long-term revenue assurances to support new entry" but also would "honor concerns expressed by FERC and others that any such revisions must not lead to undue price discrimination between existing and new resources."[78]

By the end of September, it was clear that the stakeholders were continuing to make progress on this issue, even though they had not yet come to a consensus. PJM reported as such to the Commission by letter dated October 3, 2011 in the MOPR proceeding. PJM's letter also advised that it would be in a position to report further when it submitted the RPM Performance Assessment at the end of November.

The subsequent stakeholder process has made clear that the stakeholders do not support major changes to NEPA at this time, but do support further efforts to develop a voluntary long-term auction within RPM that could serve as a new non-discriminatory means of supporting capacity investment. The RPM Performance Assessment also expressly supports the concept of a voluntary long-term auction.[79] Such an auction would precede the BRA; accordingly, there is little time to develop, file, and obtain Commission approval for a new voluntary auction structure before the next BRA that is scheduled for May 2012. PJM is committed, however, to pursuing development of this approach for implementation before the following BRA, scheduled for May 2013.

Accordingly, PJM is replacing the current outdated provision that set the October 1, 2011 target for filing NEPA changes with a new provision that provides:

> On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.[80]

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78 Tariff, Attachment DD, section 5.14(c)(8) (eTariff record OATT Attachment DD.5.14).

79 RPM Performance Assessment at viii (supporting "PJM's effort to add centralized but voluntary auctions for long-term capacity products as a supplement to the 3-year forward base auctions (*e.g.*, for a duration of 3, 5, and 7 years starting with the BRA delivery year)" as a means "[t]o increase forward price transparency and facilitate bilateral long-term contracting" and "increase the transparency and liquidity of the long-term capacity market without risking the kinds of distortions that would be caused to auction prices . . . by broadening [NEPA])."

80 Tariff, Attachment DD, section 5.14(c)(8) (eTariff record OATT Attachment DD.5.14).

C. Update to MOPR Asset Class Cost Estimates.

The current Tariff uses new entry cost estimates not only for the VRR Curve but also in MOPR, under which PJM compares sell offers from CT and CC plants against Net Asset Class CONEs for, respectively, CT and CC plants. The Commission has repeatedly found that it is reasonable for the MOPR CONE estimates to be consistent with the VRR Curve CONE estimates.

Recognizing this, Brattle's 2011 CONE Study estimated gross CONE not only for a CT plant but also for a CC plant. Brattle identified a 2x1 plant configuration as the representative technology, consistent with the predominant plant type among recent CC additions in PJM and nationally. And, like the representative CT plant described above, employed the latest GE Frame 7FA.05 turbine model. Like most recently built CC plants, the CC reference technology envisioned by Brattle uses SCR technology to control NO_x emissions. The plant's net heat rate at 59° F is 6,722 btu/kWh at full baseload output without duct-firing. In the 2011 CONE Study, Brattle found that, when using a nominal levelized financial model, the estimated June 1, 2015 CONE figures for the CC plant in each CONE Area are as follows:[81]

CONE Area	CC Level-Nominal Gross CONE *($/MW-y)*
CONE Area 1	$168,200
CONE Area 2	$147,600
CONE Area 3	$162,200
CONE Area 4	$161,800
CONE Area 5	$143,800

Given the new detailed estimates provided in the 2011 CONE Study for both a CT and CC plant, PJM is updating the Net Asset Class CONE values in the MOPR for both a CC and CT plant. The CT CONE values will be the same as those discussed earlier in this transmittal letter for the VRR Curve. The CC CONE values will be those set forth in the table above. PJM also is revising the heat rate stated for the CC plant in the MOPR to match the more efficient heat rate provided by the latest turbine model.

Finally, PJM is clarifying that the proposed new Peak-Hour Dispatch approach, taking into account both day-ahead commitments and real-time dispatch for determining revenues, will apply to the MOPR Net CONE values, just as proposed for use in connection with the VRR Curve.

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81 2011 CONE Study at 3.

V. EFFECTIVE DATE.

PJM is required to post by February 1, 2012 the auction parameters for the next RPM BRA, which is scheduled for May 2012. Those parameters include the VRR Curves, the Cost of New Entry, the Net EAS Revenue Offsets, the minimum annual and extended summer resource requirements, and the MOPR screen levels, all of which will be affected by the Tariff changes in this filing. Accordingly, the enclosed revisions incorporate an effective date of January 31, 2012, which is more than 60 days after the date of this filing.

VI. CORRESPONDENCE

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

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VII. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;

2. Revisions to the PJM Tariff (in redlined and non-redlined format (as Attachments A and B, respectively) and in electronic tariff filing format as required by Order No. 714);

3. Affidavit of Dr. Paul M. Sotkiewicz on behalf of PJM, as Attachment C;

4. Affidavit of Dr. Samuel A. Newell on behalf of PJM, with attached resume and 2011 CONE Study (as Exhibits 1 and 2, respectively), as Attachment D; and

5. 2011 RPM Performance Assessment, as Attachment E.

VIII. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[82] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region[83] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

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[82] *See* 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

[83] PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

IX. CONCLUSION

Accordingly, PJM requests that the Commission accept the enclosed Tariff revisions effective January 31, 2012.

Respectfully submitted,

/s/ *Paul M. Flynn*

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December 1, 2011

Attachment A

PJM Open Access Transmission Tariff

(Marked Sections / Redline Format)

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider or ILR Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a PJM Member that has the capability to reduce load, or that aggregates customers capable of reducing load. The Demand Resource Provider shall notify the Office of the Interconnection whether such load reduction is provided by a Limited Demand Resource, Extended Summer Demand Resource or an Annual Demand Resource. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource.

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Extended Summer Demand Resource Reliability Target

"Extended Summer Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement. As more fully set forth in the PJM Manuals, PJM calculates the Extended Summer DR Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Extended Summer Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 [Reserved]

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A Final Zonal ILR Price

"Final Zonal ILR Price" shall mean the Adjusted Zonal Capacity Price after the Second Incremental Auction, less the amount paid in CTR credits per MW of load in the Zone in which the ILR is to be certified.

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 Forecast RTO ILR Obligation

"Forecast RTO ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the PJM Region times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region, for use in Delivery Years through May 31, 2012.

2.30 Forecast Zonal ILR Obligation

"Forecast Zonal ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the Zone times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in such Zone, for use in Delivery Years through May 31, 2012.

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 ILR Forecast

"ILR Forecast" shall mean, for any Delivery Year ending on or before May 31, 2012, the average annual megawatt quantity of ILR certified for the five Planning Periods preceding the date of the forecast; provided, however, that before such data becomes available for five Delivery Years under the Reliability Pricing Model, comparable data on Active Load Management (as defined in the preexisting reliability assurance agreements) from up to five prior Planning Periods shall be substituted as necessary; and provided further that, for transmission zones that were integrated into the PJM Region less than five years prior to the conduct of the Base Residual Auction for the Delivery Year, data on incremental load subject to mandatory interruption by Electric Distribution Companies within such zones shall be substituted as necessary.

2.33 ILR Provider

"ILR Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as such term is defined in the PJM Operating Agreement, may be an ILR Provider, provided it obtains certification of its load reduction capability as ILR.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Interruptible Load for Reliability (ILR)

"Interruptible Load for Reliability" or "ILR" shall have the meaning specified in the Reliability Assurance Agreement.

2.36A Limited Demand Resource

"Limited Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for the PJM Region or such LDA.

As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; and ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result. Second, PJM adopts the lower result from these two tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area*, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction for the Zones comprising such Locational Deliverability Area for such Delivery Year*.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement ~~minus [the Short-Term Resource Procurement Target for the PJM Region in Unforced Capacity]~~ minus [the Extended Summer Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement ~~minus [the Short-Term Resource Procurement Target for such LDA in Unforced Capacity]~~ minus [the LDA CETL] minus [the Extended Summer Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement ~~minus [the Short-Term Resource Procurement Target for the RTO in Unforced Capacity]~~ minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement ~~minus [the Short-Term Resource Procurement Target for the LDA in Unforced Capacity]~~ minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 Nominated ILR Value

"Nominated ILR Value" shall mean the amount of load reduction that an ILR resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For ILR, the maximum Nominated ILR Capacity Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the ILR is certified.

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market ~~dispatched~~ in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead~~real-time~~ LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed ~~dispatched~~ independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed ~~dispatched~~ for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region*, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction (as applicable) for such Delivery Year*.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology in CONE Areas 1, 2, 3, and 4, dual fuel capability, and a heat rate of 10.096~~10,500~~ Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-

Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 Transition Adder

"Transition Adder" shall mean a component of a Sell Offer permitted for certain Capacity Market Sellers for the Transition Period, as set forth in section 17.

2.68 Transition Period

"Transition Period" shall mean the four-year period consisting of the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, *and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.*

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus

3%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the EMAAC, SWMAAC and MAAC LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such

Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry ~~for the PJM Region shall be $112,868 per MW-year. The Cost of New Entry~~ for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	134,000~~122,040~~
BGE, PEPCO ("CONE Area 2")	123,700~~112,868~~
AEP, Dayton, ComEd, APS, DQL, ATSI, *DEOK* ("CONE Area 3")	123,500 ~~115,479~~
PPL, MetEd, Penelec ("CONE Area 4")	130,100~~112,868~~
Dominion ("CONE Area 5")	111,000~~112,868~~

B) Beginning with the 2013-2014 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined~~the PJM Region~~ as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) the average hourly LMPs for the transmission zone in which such resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals); (3) fuel prices reported during such period at ~~an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals,~~ a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region, as set forth in the PJM manuals; (4) assumed variable operation and maintenance expenses for such resource of $6.47 per MWh~~, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period~~; and (~~3~~5) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year. If a sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated.

B) The Office of the Interconnection ~~also~~ shall ~~determine a~~ set the Net Cost of New Entry ~~Energy and Ancillary Market Revenue~~

~~Offset each year~~ for ~~each sub-region of~~ the PJM Region equal to the median value of the Net ~~for which the~~ Cost of New Entry for all CONE Areas as ~~is~~ determined in accordance with the foregoing provisions~~, as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the transmission zone in which such resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region~~. The Cost of New Entry for the PJM Region shall be set equal to the gross Cost of New Entry component of the selected median value of the Net Cost of New Entry.

vi) Adjustment to Net Energy and Ancillary Services Revenue Offset

Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.

vii) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the

Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the sum of the following: (1) the marginal value of system capacity for the PJM Region, without considering locational constraints, (2) the Locational Price Adder, if any in such LDA, (3) the Annual Resource Price Adder, if any, and (4) the Extended Summer Resource Price Adder, if any, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a ~~such~~ Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in ~~such~~ the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for~~in~~ the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity at or above a megawatt quantity at the price-quantity ~~corresponding to a~~ point on the VRR Curve at which the ~~where~~ price is ~~no greater than~~ 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd); and

~~3~~4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the ~~then-current~~ Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or~~.~~

(iii) ~~I~~if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted~~it~~ shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section

5.14(c)(1)-(3) that is entitled to compensation ~~for such first year~~ pursuant to section 5.14(b) of this Attachment~~.~~; and

(v) ~~T~~the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect ~~such resubmission~~the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) ~~under this provision~~ shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer ~~Price~~ price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

~~4)~~8. On or before August ~~October~~ 1, ~~2011~~2012, PJM shall file with FERC under FPA section 205~~, revisions to this section 5.14(c)~~ as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment. ~~to address concerns expressed by some parties that this provision in its current form may not provide adequate long-term revenue assurances to support new entry. Any such changes also shall honor concerns expressed by FERC and others that any such revisions must not lead to undue price discrimination between existing and new resources.~~

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the

Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets as described in sections 5.13 and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; and 4) an adjustment, if required, to account for Resource Make-Whole Payments, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); and (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity). The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall, through May 31, 2012, calculate and post the Final Zonal Capacity Price after all ILR resources are certified for the Delivery Years and, thereafter, shall calculate and post such price after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction. For such purpose, for the three consecutive Delivery Years ending May 31, 2012 only, the Forecast ILR allocated to loads located in the AEP transmission zone that are served under the Reliability Pricing Model shall be in proportion for each such year to the load ratio share of such RPM loads compared to the total peak loads of such zone for such year; and any remaining ILR Forecast that otherwise would be allocated to such loads shall be allocated to all Zones in the PJM Region pro rata based on their Preliminary Zonal Peak Load Forecasts.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Planned Generation Capacity Resources

(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the Delivery Year commencing on June 1, 2014, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT") and a combined cycle generator ("CC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CT $/MW-yr	134,000~~138,646~~	123,700~~128,226~~	123,500~~131,681~~	130,100~~128,226~~	111,000~~128,340~~
CC $/MW-	168,200~~175,250~~	147,600~~154,870~~	162,200~~164,375~~	161,800~~154,870~~	143,800~~154,870~~

yr					

(2) Beginning with the Delivery Year that begins on June 1, 2015, the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722~~6.980~~ MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year.

(4) Any Sell Offer that is based on a Planned Generation Capacity Resource submitted in an RPM Auction for the first Delivery Year in which such resource qualifies as a Planned Generation Capacity Resource, or submitted in any RPM Auction for that or any subsequent Delivery Year until the offer first clears an RPM Auction, in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions for Delivery Years beginning on or after June 1, 2014.

(5) A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection if the Capacity Market Seller obtains a determination from the Office of the Interconnection prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the

resource to rely solely on revenues from PJM-administered markets . The following process and requirements shall apply to requests for such determinations:

(i) The Capacity Market Seller may request such a determination at any time, but no later than 60 days prior to the auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a request with full documentation as described below and in the PJM Manuals. A Capacity Market Seller may request such a determination before the minimum offer level specified in subsection (4) is established for the relevant Delivery Year, based on the minimum offer level established for the prior Delivery Year or other reasonable estimate of the minimum offer level expected for the relevant Delivery Year. In such event, if the minimum offer level subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for an exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the Office of the Interconnection and the Market Monitoring Unit. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer.

(iii) A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, nominal levelized, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4). Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of an exception hereunder by the Office of the Interconnection.

(iv) the determination required under this subsection shall be provided to the Capacity Market Seller in writing by the Office of the Interconnection no later than 45 days after receipt of the request. The Market Monitoring Unit shall first review the information and documentation in support of the request and shall provide its findings in accordance with the standards and criteria hereunder in writing simultaneously to the Capacity Market Seller and the Office of the Interconnection no later than 30 days after receipt of such request. If the findings of the Market Monitoring Unit are adverse to the Capacity Market Seller, such Capacity Market Seller may request, through written notice within 5 days of its receipt of the Market Monitoring Unit's findings, review by the Office of the Interconnection, provided, however, that the Office of the Interconnection as Tariff administrator may elect to review any Market Monitoring Unit determination hereunder on its own initiative.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal

Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

Attachment B

PJM Open Access Transmission Tariff
(Clean Sections)

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider or ILR Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a PJM Member that has the capability to reduce load, or that aggregates customers capable of reducing load. The Demand Resource Provider shall notify the Office of the Interconnection whether such load reduction is provided by a Limited Demand Resource, Extended Summer Demand Resource or an Annual Demand Resource. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource.

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Extended Summer Demand Resource Reliability Target

"Extended Summer Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement. As more fully set forth in the PJM Manuals, PJM calculates the Extended Summer DR Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Extended Summer Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 [Reserved]

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A Final Zonal ILR Price

"Final Zonal ILR Price" shall mean the Adjusted Zonal Capacity Price after the Second Incremental Auction, less the amount paid in CTR credits per MW of load in the Zone in which the ILR is to be certified.

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 Forecast RTO ILR Obligation

"Forecast RTO ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the PJM Region times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region, for use in Delivery Years through May 31, 2012.

2.30 Forecast Zonal ILR Obligation

"Forecast Zonal ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the Zone times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in such Zone, for use in Delivery Years through May 31, 2012.

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 ILR Forecast

"ILR Forecast" shall mean, for any Delivery Year ending on or before May 31, 2012, the average annual megawatt quantity of ILR certified for the five Planning Periods preceding the date of the forecast; provided, however, that before such data becomes available for five Delivery Years under the Reliability Pricing Model, comparable data on Active Load Management (as defined in the preexisting reliability assurance agreements) from up to five prior Planning Periods shall be substituted as necessary; and provided further that, for transmission zones that were integrated into the PJM Region less than five years prior to the conduct of the Base Residual Auction for the Delivery Year, data on incremental load subject to mandatory interruption by Electric Distribution Companies within such zones shall be substituted as necessary.

2.33 ILR Provider

"ILR Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as such term is defined in the PJM Operating Agreement, may be an ILR Provider, provided it obtains certification of its load reduction capability as ILR.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Interruptible Load for Reliability (ILR)

"Interruptible Load for Reliability" or "ILR" shall have the meaning specified in the Reliability Assurance Agreement.

2.36A Limited Demand Resource

"Limited Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for the PJM Region or such LDA.

As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; and ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result. Second, PJM adopts the lower result from these two tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area*, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction for the Zones comprising such Locational Deliverability Area for such Delivery Year*.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Extended Summer Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Extended Summer Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual

Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 Nominated ILR Value

"Nominated ILR Value" shall mean the amount of load reduction that an ILR resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For ILR, the maximum Nominated ILR Capacity Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the ILR is certified.

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

“Peak-Hour Dispatch” shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

“Peak Season” shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

“Percentage Internal Resources Required” shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

“Planned Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

“Planned External Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

“Planned Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

“Planning Period” shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region*, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction (as applicable) for such Delivery Year*.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology in CONE Areas 1, 2, 3, and 4, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 Transition Adder

"Transition Adder" shall mean a component of a Sell Offer permitted for certain Capacity Market Sellers for the Transition Period, as set forth in section 17.

2.68 Transition Period

"Transition Period" shall mean the four-year period consisting of the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant

Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used*, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.*

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin (“IRM”)% minus

3%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the EMAAC, SWMAAC and MAAC LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such

Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	134,000
BGE, PEPCO ("CONE Area 2")	123,700
AEP, Dayton, ComEd, APS, DQL, ATSI, *DEOK* ("CONE Area 3")	123,500
PPL, MetEd, Penelec ("CONE Area 4")	130,100
Dominion ("CONE Area 5")	111,000

B) Beginning with the 2013-2014 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) the average hourly LMPs for the transmission zone in which such resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals); (3) fuel prices reported during such period at a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region, as set forth in the PJM manuals; (4) assumed variable operation and maintenance expenses for such resource of $6.47 per MWh; and (5) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year. If a sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated.

B) The Office of the Interconnection shall set the Net Cost of New Entry for the PJM Region equal to the median value of the Net Cost of New Entry for all CONE Areas as determined in accordance with the foregoing provisions. The Cost of New Entry for the PJM Region shall be set equal to the gross Cost of New Entry component of the selected median value of the Net Cost of New Entry.

vi) Adjustment to Net Energy and Ancillary Services Revenue Offset

Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.

vii) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the sum of the following: (1) the marginal value of system capacity for the PJM Region, without considering locational constraints, (2) the Locational Price Adder, if any in such LDA, (3) the Annual Resource Price Adder, if any, and (4) the Extended Summer Resource Price Adder, if any, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd); and

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflectthe resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets as described in sections 5.13 and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; and 4) an adjustment, if required, to account for Resource Make-Whole Payments, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); and (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity). The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall, through May 31, 2012, calculate and post the Final Zonal Capacity Price after all ILR resources are certified for the Delivery Years and, thereafter, shall calculate and post such price after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing

Demand Resource cleared in the Base Residual Auction and Second Incremental Auction. For such purpose, for the three consecutive Delivery Years ending May 31, 2012 only, the Forecast ILR allocated to loads located in the AEP transmission zone that are served under the Reliability Pricing Model shall be in proportion for each such year to the load ratio share of such RPM loads compared to the total peak loads of such zone for such year; and any remaining ILR Forecast that otherwise would be allocated to such loads shall be allocated to all Zones in the PJM Region pro rata based on their Preliminary Zonal Peak Load Forecasts.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Planned Generation Capacity Resources

(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the Delivery Year commencing on June 1, 2014, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT") and a combined cycle generator ("CC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CT $/MW-yr	134,000	123,700	123,500	130,100	111,000
CC $/MW-yr	168,200	147,600	162,200	161,800	143,800

(2) Beginning with the Delivery Year that begins on June 1, 2015, the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year.

(4) Any Sell Offer that is based on a Planned Generation Capacity Resource submitted in an RPM Auction for the first Delivery Year in which such resource qualifies as a Planned Generation Capacity Resource, or submitted in any RPM Auction for that or any subsequent Delivery Year until the offer first clears an RPM Auction, in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions for Delivery Years beginning on or after June 1, 2014.

(5) A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection if the Capacity Market Seller obtains a determination from the Office of the Interconnection prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets . The following process and requirements shall apply to requests for such determinations:

(i) The Capacity Market Seller may request such a determination at any time, but no later than 60 days prior to the auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a request with full documentation as described below and in the PJM Manuals. A Capacity Market Seller may request such a determination before the minimum offer level specified in subsection (4) is established for the relevant Delivery Year, based on the minimum offer level established for the prior Delivery Year or other reasonable estimate of the minimum offer level expected for the relevant Delivery Year.

In such event, if the minimum offer level subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for an exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the Office of the Interconnection and the Market Monitoring Unit. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer.

(iii) A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, nominal levelized, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4). Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of an exception hereunder by the Office of the Interconnection.

(iv) the determination required under this subsection shall be provided to the Capacity Market Seller in writing by the Office of the Interconnection no later than 45 days after receipt of the request. The Market Monitoring Unit shall first review the information and documentation in support of the request and shall provide its findings in accordance with the standards and criteria hereunder in writing simultaneously to the Capacity Market Seller and the Office of the Interconnection no later than 30 days after receipt of such request. If the findings of the Market Monitoring Unit are adverse to the Capacity Market Seller, such Capacity Market Seller may request, through written notice within 5 days of its receipt of the Market Monitoring Unit's findings, review by the Office of the Interconnection, provided, however, that the Office of the Interconnection as Tariff administrator may elect to review any Market Monitoring Unit determination hereunder on its own initiative.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

Attachment C

Affidavit of Dr. Paul M. Sotkiewicz on behalf of PJM

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER12-______

AFFIDAVIT OF DR. PAUL M. SOTKIEWICZ
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Dr. Paul M. Sotkiewicz, and I am the Chief Economist in the Market Service Division at the PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit in support of two proposals in PJM's filing related PJM's capacity market, known as the Reliability Pricing Model ("RPM"): 1) The use of a nominal levelized approach to calculating the estimated Cost of New Entry ("CONE") that is used in RPM's Variable Resource Requirement ("VRR") Curve; and 2) ending the recently implemented practice of subtracting the Short Term Resource Procurement Target ("STRPT" or "holdback") from certain minimum resource procurement requirements that are used in the RPM auctions.

2. As the Chief Economist at PJM, I provide expert analysis, advice, and support for PJM initiatives related to market design changes in, and performance of, PJM's energy, ancillary service, and capacity markets. In particular, I have worked extensively on demand response mechanisms, the development of shortage pricing mechanisms to comply with the Commission's Order No. 719, the integration of intermittent renewable resources into PJM's markets, market power mitigation issues, and (most recently) potential changes to RPM in conjunction with a review of RPM mandated by PJM's Open Access Transmission Tariff ("Tariff"). Additionally, I provide expert analysis on major policy issues facing PJM and have led research efforts that have resulted in whitepapers on the impact of potential climate change policies on PJM's energy markets, transmission cost allocation methods used here and abroad, and the effect of EPA's Cross State Air Pollution Rule and National Emissions Standards for Hazardous Air Pollutants on potential coal capacity retirements in the PJM region. Prior to joining PJM, I served as the Director of Energy Studies at the Public Utility Research Center, University of Florida and as an Economist at the United States Federal Energy Regulatory Commission. I have a B.A. in History and Economics from the University of Florida, and an M.A. and Ph.D. in Economics from the University of Minnesota.

I. <u>Use of the Nominal Levelized Financial Modeling Method to Calculate CONE.</u>

3. As used in RPM's VRR Curve, CONE is an estimate of the capital costs and fixed operations and maintenance expenses for a new natural gas combustion turbine plant. Dr. Samuel A. Newell, of The Brattle Group ("Brattle") presents Brattle's detailed,

comprehensive estimate of CONE with the affidavit he is submitting as part of PJM's Tariff change filing in this proceeding. I am addressing only one aspect of the CONE estimate, i.e., which form of levelized cost model should be used to prepare that estimate.

4. Translating project investment and fixed operations and maintenance costs for new generation over the expected economic life of the generation project into a levelized annual cost is standard practice in the utility industry. The levelized annual cost provides information to the project developer, regulators, and counterparties concerning the constant stream of revenues needed each year to cover the cost of the project including returns on capital. That constant stream of payments can be expressed in either "real" or "nominal" terms.

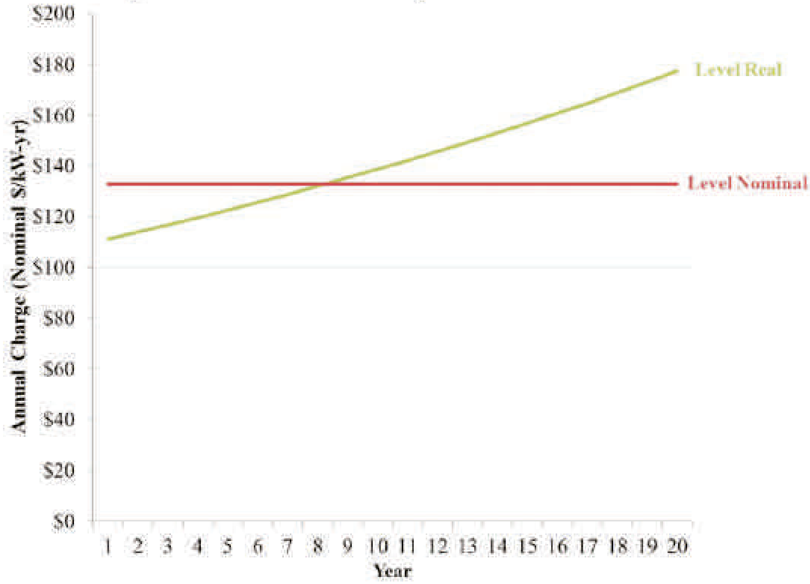
5. Expressing the constant stream of payments in nominal terms, ("nominal levelized"), means that the payment in each year is the same regardless of inflation. Under nominal levelized, the project developer would receive the same dollar amount (e.g. $120,000/MW-year) in each year over the life of the project regardless of the assumed rate of inflation over the life of the project.

6. Expressing the constant stream of payments in real terms ("real levelized"), means that the payment each year, while the same on an inflation-adjusted basis, increases each year over the life of the project by the rate of inflation.

7. For any given assumed rate of inflation, the present value of the stream of payments under either nominal levelized or real levelized is exactly the same. What differs is the trajectory of the payments in nominal terms. Below I have reproduced Figure 14 from Brattle's RPM Performance Assessment (which is being submitted to the Commission with this filing) that shows the nominal levelized cost recovery as the flat line and the real levelized cost recovery as the line that increases over the life of the project.

8. Under nominal levelized cost recovery, the payments made in the early years are greater than the payments in the early years under real levelized cost recovery. However in the later years the nominal levelized payments are less than the real levelized payments. Figure 14 from the RPM Performance Assessment shows nominal levelized payments recover more of the project cost in the early years and less of the project cost in later years. Conversely, Figure 14 shows real levelized payments recover less of the project cost in the early years and more of the project cost in the later years of the project.

Figure 14
Comparison of Cost Recovery Paths for a New CT Plant



9. In connection with preparation of its CONE estimate, Brattle has recommended that PJM and its stakeholders should consider transitioning from the nominal levelized method (which PJM has used to set CONE since RPM's inception) to a real levelized approach. However, Brattle's recommendation is contingent on 1) significantly revising RPM's Energy and Ancillary Service ("EAS") Revenue offset estimating method; and 2) revising the VRR Curve's shape. While PJM is proposing to revise the VRR curve in this proceeding, it is not adopting Brattle's more significant suggested changes to calculation of the EAS revenue offset.

10. To support its recommended movement toward real-levelized CONE, Brattle provides historic evidence of the inflation rate for the cost of new CTs as shown by the Handy-Whitman Index, a well-recognized utility construction cost index. Brattle's analysis indicates a 60 basis point (0.60%) higher rate of inflation for CT costs than the historic Consumer Price Index ("CPI"). However Brattle also notes that CT heat rate improvement over time (due to technological progress) largely offsets the difference between the Handy-Whitman Index and the CPI. From this, Brattle concludes that because CT costs on net rise by the rate of inflation based on historic evidence, project developers will expect the projects revenues to rise at the inflation rate, warranting PJM's adoption of the real-levelized model that likewise assumes revenues will rise at an assumed inflation rate.

11. Brattle's assumption about project developer's expectations regarding future revenue increases highlights the central challenge with adopting a real levelized approach. The Commission addressed this very same issue earlier this year, when certain parties advocated using the real levelized approach to estimate the CONE estimate that is used to screen capacity offers under RPM's Minimum Offer Price Rule. In that case, the Commission found that, even with a gross CONE escalation rate of only 2.5 percent

under the real levelized method, the EAS offset and other factors would imply an effective inflation rate of 6.0 percent, which the Commission found to be an unreasonable expectation to ascribe to a developer. By contrast, the Commission found that it would be reasonable for a developer to use a nominal levelized approach, since it matches the mortgage style financing that is typical for new generation projects.

12. In my view, the issue here is not whether it is reasonable for Brattle to project that CT plant revenues will steadily increase every year at a particular inflation rate. The issue is whether it is *unreasonable* to expect that a *developer* will want the assurance of a constant revenue stream (on a nominal levelized basis) in order to go forward with a new entry project. Brattle's analysis does not show that. In fact, there are ample reasons to expect that a developer might be wary of the risks implicit in a real levelized model. In other words, a developer legitimately might decline to invest if it is at risk of not receiving the annual revenue increases on which the nominal levelized model depends.

13. First, while Brattle's preference for real levelized assumes that the RPM capacity market will be in a long-run steady-state where RPM prices evolve by the rate of inflation because the Reference Resource CT will always be the marginal resource, there are a variety of reasons why the market may be thrown off such a long-run steady state, even if it reaches that state. There may be periods of slow load growth due to extended periods of sluggish macroeconomic performance, as we are experiencing currently, that may not support a new CT as the marginal resource. There may also be technological changes that allow for resources to meet resource adequacy requirements at lower costs, such as demand response or energy efficiency, as has been observed in RPM, to help meet installed reserve margin targets for a period of time before such lower cost alternatives are exhausted.

14. Second, Brattle's analysis assumes that the EAS offset evolves by the same rate of inflation as the CONE value. But movements in supply-demand conditions and consequently prices in fuel markets can have a huge impact on the level of the EAS offset that is earned by the reference resource, with some years growing by more than inflation, and other years by far less than inflation. Such trends could last for years. EAS offsets also vary with weather, with years of extreme weather leading to higher EAS offsets and mild weather, as we observed in 2009 and 2010, leading to much lower EAS offsets. In addition, policy changes, such as renewable portfolio standards or climate change policies, can affect EAS revenues of new entry CTs that may not have been anticipated when the project was first developed.

15. Third, Brattle's preference for a real levelized approach also critically assumes that generation project developers are risk neutral rather than risk averse. But developer risk aversion is the heart of the matter, and must be confronted. Project developers may quite reasonably be risk averse for a host of reasons, including the inflation uncertainties and EAS revenue uncertainties described above. And RPM must deal with project developers as they are, not as some might wish them to be. Project developers that are risk averse may prefer to receive a greater share of cost recovery in the early years of the project's life given that forecasts about future market conditions and

policies affecting the industry 5, 10, 15, and 20 years forward grow ever more uncertain as highlighted above. In fact in its survey of market participants as part of the RPM Performance Assessment, Brattle observes on page 53 that both buyers and sellers would prefer to extend forward certainty. Brattle notes that generation owners report that buyers for long-term bilateral contracts are simply not available beyond terms of 3 to 5 years. Such observations confirm that generation developers are risk averse as they would prefer to lock-in prices to guard against the kinds of economic, technological, policy, fuel market, and weather uncertainties described above. Absent certainty about the future stream of payments, project developers would likely prefer to recover project investment costs in the early years of the project rather than in later years.

16. Moreover, the choice between real levelized and nominal levelized approaches ultimately must confront the implications of those differing approaches, and of possible project developer risk aversion, on resource adequacy and reliability. Suppose, as recommended by Brattle, the first year real-levelized CONE was used to define the VRR Curve. The implication is that at Point 2 on the VRR Curve, at the quantity of the Installed Reserve Margin ("IRM")+1%, the price of capacity on the VRR Curve would be defined by a Net CONE that would not be high enough to incent new entry from risk averse generation project developers if new entry was needed to meet the target installed reserve margin. There would only be incentives for new entry from risk averse generation developers at higher RPM prices that are reflected by the nominal levelized recovery of costs, but at installed reserve margins that were below the target installed reserve margin, resulting in an erosion of the performance of RPM to maintain resource adequacy reliability at the target installed reserve margin.

17. In sum, the nominal levelized modeling approaching to calculating CONE remains reasonable, and Brattle's reasons for preferring a real levelized approach do not demonstrate that the nominal levelized approach is unreasonable.

II. Ending the Practice of Subtracting the Short Term Resource Procurement Target From the Minimum Requirements for Certain Resource Categories.

18. The Short Term Resource Procurement Target ("STRPT") was introduced into RPM beginning with the 2012/2103 Delivery Year ("DY") and "holds back" 2.5 percent of the total reliability requirement targeted for procurement in the Base Residual Auction ("BRA") to allow Demand Resources ("DR") that may be unable to commit as capacity three years before the DY an opportunity to commit in an Incremental Auction ("IA") closer to the DY.

19. Prior to the 2012/2013 DY, parties could commit load reduction capability either as a Demand Resource in an RPM forward auction or as Interruptible Load for Reliability ("ILR"), simply be registering as ILR shortly before the start of the DY. To encourage load reductions to compete with other capacity resources in the RPM auctions, PJM eliminated ILR, with Commission approval, as of the end of the 2011/2012 DY. But to recognize that some market participants could not make firm commitments of load

reduction capabilities three years before the DR, PJM adopted the STRPT. As implemented beginning with the 2012/2013 DY, the STRPT reduces by 2.5% the Reliability Requirement that is sought in the BRA, and then seeks to obtain that deferred resource requirement for the relevant DY over the course of the three Incremental Auctions for that DY.

20. Earlier this year, the Commission approved PJM's proposal to establish two new types of Demand Resource products, as a way to address concerns that PJM's pre-existing Demand Resource product was only obligated to respond to PJM emergencies a maximum of 10 events during the summer period for a maximum of 6 hours each event, and a heavy reliance on such limited resources could jeopardize resource adequacy reliability. The two new Demand Resource products, known as Annual Demand Resources and Extended Summer Demand Resources, have fewer limits on their availability and thus greater reliability value for the PJM region. Extended Summer Demand Resource can be called on an unlimited number of times during an "extended" five-month summer period, while Annual Resources can be called on an unlimited number of times during the entire year. To ensure that PJM did not over-rely on the pre-existing, more limited product, PJM proposed to set minimum requirements for the two new products, i.e., the Minimum Annual Resource Requirement and Minimum Extended Summer Resource Requirement. However, PJM also modified its Tariff at this time to apply the full STRPT to both the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement. In other words, just as PJM reduces its overall resource procurement target in the BRA by the amount of the holdback, and then seeks to recover that quantity in the IAs, the new rules direct PJM to reduce in the BRA the minimum quantities of these two resource types that it will seek to procure, and then seek to recover the remainder of those minimum quantities in the IAs.

21. Similar to RPM's locational pricing, the new product types can "price-separate." If PJM has not met its minimum requirement for a product type, e.g., annual resources, the RPM auction will clear more of the needed product type, even if it must pay the seller a higher price to commit that resource type.

22. To increase market participant flexibility with the introduction of the two new Demand Resource products, PJM revised the Tariff to allow capacity market sellers to submit "coupled" offers, in which a single resource that meets all the qualification criteria for multiple product types would offer at differing prices to be one product type or a second product type (or even a third) depending on the system's needs for the varying product types and whether a price premium is in effect for one of the product types. Under this flexible approach, if prices have not separated, the resource will be committed as a more limited resource type. But if prices separate such that product types with fewer availability limits command a premium price, and the resource qualifies for that resource type, it will be committed as that type of resource and paid the higher price With this flexibility and coupling of offers as different resource types, the Demand Resource would be committed as the resource type that maximizes the value to the provider and to the PJM Region.

23. PJM has applied these new rules in one RPM auction—the BRA earlier this year for the 2014/2015 DY. In accordance with the Tariff, the STRPT was applied in that BRA to the overall Reliability Requirement, to the Minimum Annual Resource Requirement, and to the Minimum Extended Summer Resource Requirement. The table below shows the overall 2014/2015 DY Reliability Requirement, Minimum Extended Summer Resource Requirement, and Minimum Annual Resource Requirement, the same values adjusted for the STRPT, the amount of capacity of each type cleared in the 2014/2015 BRA, and the amount of each type of capacity that can be procured in the IAs. In examining the table it is important to realize that "higher quality" resources can be used to satisfy the requirements for "lower quality" resources e.g., Annual Resources can be used to satisfy the requirement for Extended Summer Resources

2014/2015 Delivery Year Base Residual Auction

	Before STRPT	After STRPT	Procured Amount	IA Potential
Reliability Requirement	148,323	144,615	149,975	3,708
Minimum Extended Summer Requirement	141,517	137,809	137,809	3,708
Minimum Annual Requirement	132,158	128,450	136,368	3,708

24. The actual procurement shows the Minimum Extended Summer Resource Requirement, less the holdback, was procured in the BRA. However, going into the IAs there is still 3,708 MW of the Minimum Extended Summer Resource Requirement that must be procured, and this equals exactly the amount of the overall holdback that must be procured in the IAs. Put another way, the holdback must be recouped in the IA using only resources that can satisfy the Minimum Extended Summer Resource Requirement, i.e., Annual Resources or Extended Summer Resources. Since Limited Demand Resources cannot satisfy the Minimum Extended Summer Resource Requirement, and since the overall holdback is coextensive with the deferred portion of the Minimum Extended Summer Resource Requirement that remains to be procured, then (assuming no change in the Reliability Requirement) Limited Demand Resources cannot satisfy the holdback in the Incremental Auctions for the 2014/2015 DY. Limited DR might as well not even participate in the IAs (under this scenario) because they cannot be selected to clear. Therefore, an unintended result of the current STRPT is the potential exclusion of Limited Demand Resources from satisfying the holdback, denying these resources the opportunity to exercise a short lead time business strategy and commit to RPM closer to the DY. Such an outcome is exactly the opposite of what was intended with the implementation of the STRPT.

25. In addition to not functioning as intended for Limited Demand Resources, the fact that the current STRPT is holding back Annual and Extended Summer Resources raises the concern that the prices of these resources in the BRA could be unintentionally suppressed. As Brattle has outlined very clearly in the RPM Performance Assessment, by holding back resources that are otherwise subject to market power mitigation, which are Annual Resources such as existing generators, the current holdback can suppress prices in the BRA for Annual Resources. Suppliers with a "must-offer" requirement and mitigated offers do not have the option of increasing offers in the BRA or shifting offers to IAs. But the current STRPT mechanism effectively takes up to 2.5 percent of Annual

and Extended Summer Resources out of the BRA and involuntarily shifts them into the IAs. If the market clears on the mitigated portion of the supply curve without a significant amount of unmitigated capacity offers clearing as infra-marginal resources, then the current STRPT mechanism likely suppresses prices for Annual and Extended Summer Resources. Brattle in the RPM Performance Assessment has noted that for Annual and Extended Summer Resources the holdback was 2.6 and 2.0 times bigger, respectively, than cleared unmitigated supply, indicating that the prices of these products were suppressed. The extent of price suppression for Annual and Extended Summer Resources will depend on the slope of the mitigated part of the supply curve that is affected by the demand held back under the current STRPT. If the mitigated supply curve is relatively flat over the range affected by the STRPT, then the degree of price suppression is minimal. However, if the mitigated supply curve is relatively steep over the range affected by the STRPT, then the extent of price suppression could be significant.

26. In light of the above unintended consequences of the current STRPT, PJM supports the Brattle recommendation to eliminate the current practice of applying the STRPT to the Minimum Extended Summer Resource Requirement and the Minimum Annual Resource Requirement, but keep the STRPT for the entire Reliability Requirement. The proposed change to the STRPT does not preclude the procurement of excess Limited DR Resources in the BRA beyond the Reliability Requirement if cost-effective, as was the case in the 2014/2015 BRA. With this change, Limited DR Resources will be eligible to satisfy the entirety of the demand for capacity held back from the BRA and procured in the IAs if they are cost-effective to do so, but there will also be potentially greater competition to satisfy that demand as both Annual and Extended Summer Resources will also be eligible to satisfy the overall holdback.

27. To show the effects of the proposed change, PJM prepared an alternative auction-clearing scenario using the parameters and supply offers from the 2014/2015 BRA but revising the STRPT to match the Tariff revisions in this filing. The results are shown in the table below. The changed requirements with the new STRPT are highlighted in yellow.

2014/2015 Delivery Year Base Residual Auction with Proposed STRPT Change

	Before STRPT	After STRPT	Procured Amount	IA Potential
Reliability Requirement	148,323	144,615	150,059	3,708
Minimum Extended Summer Requirement	141,517	141,517	141,517	3,708
Minimum Annual Requirement	132,158	132,158	136,456	3,708

28. The alternative scenario shows the entirety of the Minimum Annual Resource Requirement has been exceeded and the extra Annual Resources procured have helped satisfy the Minimum Extended Summer Resource Requirement, as was the case in the 2014/2015 BRA. And because the entirety of the STRPT was applied only to the total Reliability Requirement, Limited DR Resources are eligible to satisfy the remainder of the Reliability Requirement in the IAs, although they will be competing with Annual and Extended Summer Resources as well. Moreover, such a result should satisfy the concerns

of DR providers noted by Brattle in the RPM Performance Assessment (at p.144) regarding the risks posed by a three-year forward commitment for DR providers and short-term resources.

29. Moreover, while fewer Limited DR Resources clear in the BRA under the proposed changes, the flexibility afforded to DR by coupling offers has resulted in greater amounts of DR resources being committed as Extended Summer Resources so that effectively the approximately 3,620 MW of DR that cleared as Limited DR under the current STRPT rules would have cleared as Extended Summer Resources under the PJM proposed STRPT, so that overall the total amount of DR procured in the BRA under this scenario is effectively unchanged, but the resource type under which it has been committed has shifted.

30. Because of the ability of Demand Resources to exercise the option of submitting coupled offers as a Limited Demand Resource, an Extended Summer Resource, and as an Annual Resource, the proposed change does not discriminate against Demand Resources but rather provides even greater flexibility and more options than under the current STRPT since Demand Resources will once again have the ability to commit in an IA closer to the DY. Moreover, as Demand Resources are not subject to market power mitigation, they can submit any offer that the seller believes reflects the cost of committing to reduce load when called upon as a Capacity Resource whether it is in an IA or in a BRA. If the prices are low in the IAs it reflects the costs of the resources offering and clearing, so if IA prices remain low following the proposed change to the STRPT it is because Limited DR (and Annual and Extended Summer Resources, to the extent they offer into the IAs) has submitted offers that reflect their low cost of being a Limited Demand Resource (or the low cost to less limited resources of substituting for Limited Demand Resources). If the purpose of committing load reductions as capacity is to explicitly hedge against RPM prices and costs, load reductions can offer into the BRA as an Extended Summer or Annual Resource to ensure that it clears at the same price (or close to the same price) as the Annual and Extended Summer Resources that comprise the bulk of the Reliability Requirement in RPM.

This concludes my affidavit.

SS:) State of Washington, D.C.
)
) ~~County of~~ ____

AFFIDAVIT OF DR. PAUL M. SOTKIEWICZ

Dr. Paul M. Sotkiewicz, being first duly sworn, deposes and states that he has read the foregoing "Affidavit of Dr. Paul M. Sotkiewicz on Behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ ____
Dr. Paul M. Sotkiewicz

Subscribed and sworn to before me this 30th day of November, 2011.

/s/ ____
Notary Public

My Commission expires: 6/14/12

Attachment D

Affidavit of Dr. Samuel A. Newell on behalf of PJM

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER12-______

AFFIDAVIT OF DR. SAMUEL A. NEWELL
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Dr. Samuel A. Newell, and I am a Principal of The Brattle Group ("Brattle"). I am submitting this affidavit in support of the proposal by PJM Interconnection, L.L.C. ("PJM") to adjust the administrative Cost of New Entry ("CONE") parameter, representing the cost of building a generation plant for use in PJM's capacity market (known as the Reliability Pricing Model or "RPM").

2. In my position with Brattle, I support clients throughout the United States in regulatory, litigation, and business strategy matters involving wholesale electricity market design, contract disputes, generation asset valuation, transmission development, demand response programs, and integrated resource planning. I have written expert reports for regional transmission organizations ("RTOs") and provided testimony before state regulatory commissions and this Commission. Prior to joining Brattle, I was Director of the Transmission Service at Cambridge Energy Research Associates. Before that, I was a Manager in the Utilities Practice at A.T.Kearney. I earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and an A.B. in Chemistry and Physics from Harvard University. A complete list of my qualifications, publications, reports, and prior experience is set forth in Exhibit 1 to my affidavit.

3. In March of 2011, PJM retained Brattle to assist PJM in a review of RPM and certain of its components, including the type of generator to use for the estimated CONE, an appropriate configuration and technology for that generator, and its resulting levelized capital and fixed operations and maintenance ("O&M") costs, expressed in $/MW-Year or $/MW-Day. I led the Brattle team that conducted the CONE review and analysis.

4. The results of Brattle's review and analysis are set forth in a report entitled "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM" ("2011 CONE Study"), which was prepared under my direction and supervision. A copy of that report is provided as Exhibit 2 to my affidavit. Brattle prepared the 2011 CONE Study in cooperation with CH2M HILL, a major engineering, procurement, and construction company with extensive experience in the design and construction of power plants, and Wood Group, a power plant O&M services provider.

5. The purpose of my affidavit is to present the 2011 CONE Study and briefly summarize its conclusions as relevant to PJM's proposal in this proceeding to update the

CONE and certain related new entry costs used in RPM. The rationale and support for each such conclusion is set forth in detail in the 2011 CONE Study.

6. To determine the technical specifications of the reference combustion turbine ("CT") power plant, we relied primarily on the "revealed preference" of generation developers in the PJM region and around the U.S. as reflected by recent installations of CT plants. Based on those considerations and discussions with CH2M HILL, a multi-turbine configuration in the 400-500 MW range remains typical, and the General Electric Frame 7FA turbine used as the basis for PJM's current CONE remains a preferred choice. We have updated that configuration, however, to reflect the latest turbine model, which provides higher installed capacity and an improved heat rate compared to the current reference technology. The CONE plant configuration includes selective catalytic reduction ("SCR") technology to control oxides of nitrogen ("NO_x") emissions where needed to meet air quality requirements, based on emerging trends in air quality regulation and simple-cycle turbine project development. The plant's net heat rate is 10,094 btu/kWh at 59 °F with SCR and 10,036 btu/kWh at 59 °F without SCR.

7. The levelized gross CONE estimates are based on the total project capital cost and annual fixed O&M expenses of the selected plant configuration. We prepared separate CONE estimates for each of the five "CONE Areas" currently identified in the PJM Tariff, *i.e.*:

- CONE Area 1: Eastern MAAC (PS, JCP&L, AE, PECO, DPL, RECO);
- CONE Area 2: Southwest MAAC (PEPCo and BG&E)
- CONE Area 3: Rest of RTO (AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK);
- CONE Area 4: Western MAAC (PPL, MetEd, Penelec); and
- CONE Area 5: Dominion.

We identified an appropriate site within each CONE Area for construction of the representative plant based on considerations including proximity to electric transmission infrastructure, access to major natural gas pipelines, site attractiveness as indicated by recently built power plants, and availability of vacant industrial land.

8. The gross CONE estimates assume a project entering service by June 1, 2015 and are calculated on a levelized basis over the new entry plant's assumed twenty-year economic life. PJM proposes in this proceeding to continue determining those revenue requirements on a nominal levelized basis, i.e., representing payments constant in nominal terms over the plant's twenty-year economic life.[1] The 2011 CONE Study found

[1] Our 2011 CONE Study report also presents gross CONE on a level-real basis. In a separate, concurrent report on RPM for PJM, we recommended using level-real CONE for RPM's Variable Resource Requirement ("VRR") curve only if PJM adopts our other recommendations to change the energy and ancillary services ("E&AS") revenue offset methodology and raise the price cap of the VRR curve. We also recommended using level-real values for RPM's minimum offer price rule.

that, when using a nominal levelized financial model, the estimated June 1, 2015 CONE figures for the CT plant in each CONE Area are as reported in Table 1.

Table 1.
Level-Nominal Gross CONE of a Combustion Turbine Plant

CONE Area	CT Level-Nominal Gross CONE *($/MW-y)*
CONE Area 1	$134,000
CONE Area 2	$123,700
CONE Area 3	$123,500
CONE Area 4	$130,100
CONE Area 5	$111,000

9. We also estimated gross CONE for a representative combined cycle ("CC") plant. PJM uses combined-cycle new entry plant cost estimates for screening purposes in RPM's minimum offer price rule. We identified a 2x1 plant configuration as the representative technology, consistent with the predominant plant type among recent CC additions in PJM and nationally, and, like the representative CT plant described above, employed the latest GE Frame 7FA.05 turbine model. Like most recently built CC plants, the CC reference technology uses selective catalytic reduction technology to control NO_x emissions. The plant's net heat rate at 59° F is 6,722 btu/kWh at full baseload output without duct-firing. In our 2011 CONE Study, we found that, when using a nominal levelized financial model, the estimated June 1, 2015 CONE figures for the CC plant in each CONE Area are as reported in Table 2.[2]

Table 2.
Level-Nominal Gross CONE of a Combined Cycle Plant

CONE Area	CC Level-Nominal Gross CONE *($/MW-y)*
CONE Area 1	$168,200
CONE Area 2	$147,600
CONE Area 3	$162,200
CONE Area 4	$161,800
CONE Area 5	$143,800

This concludes my affidavit.

2 Table 2 and the attached report fixes an editing error in the originally-posted 2011 CONE Study. Certain tables in the originally-posted report understated level-nominal CC CONE by $0.1/MW-year for CONE Areas 1, 2, and 3.

	)	Commonwealth of Massachusetts
SS:	)	
	)	County of Middlesex

AFFIDAVIT OF DR. SAMUEL A. NEWELL

Dr. Samuel A. Newell, being first duly sworn, deposes and states that he has read the foregoing "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ Samuel A. Newell
Dr. Samuel A. Newell

Subscribed and sworn to before me this 1st day of December, 2011.

/s/ Debra A Paolo
Debra A. Paolo, Notary Public

My Commission expires: September 30, 2016

DEBRA A. PAOLO
Notary Public
Commonwealth of
Massachusetts
Commission Expires Sep 30, 2016

DEBRA A. PAOLO
NOTARY
PUBLIC
COMMONWEALTH OF MASSACHUSETTS

Exhibit 1 to Attachment D

Resume of Dr. Samuel A. Newell

Office: Cambridge, MA ♦ Phone: +1.617.234.5725 ♦ Email: Sam.Newell@brattle.com

Dr. Samuel Newell's expertise is in the analysis and modeling of electricity markets, the transmission system, and RTO rules. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation and development, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC.

Prior to joining *The Brattle Group*, Dr. Newell was Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T.Kearney.

Dr. Newell earned a Ph.D. in technology management and policy from the Massachusetts Institute of Technology, an M.S. in materials science and engineering from Stanford University, and a B.A. in chemistry and physics from Harvard College.

AREAS OF EXPERTISE

- *Electricity Wholesale Market Design*
- *Transmission Planning and Modeling*
- *Integrated Resource Planning*
- *Evaluation of Demand Response (DR)*
- *Valuation of Generation Assets*
- *Energy Contract Litigation*
- *RTO Participation and Configuration*
- *Analysis of Market Power*
- *Tariff and Rate Design*
- *Business Strategy*

EXPERIENCE

Electricity Wholesale Market Design

- *Review of PJM Capacity Market*. Undertook second tri-annual review of the Reliability Pricing Model. Analyzed capacity auction results and response to market fundamentals. Interviewed stakeholders and documented concerns. Addressed key market design elements and recommended improvements to reduce pricing uncertainty and safeguard future performance. Led a study of the Cost of New Entry, based on detailed engineering estimates developed by EPC contractor CH2M HILL, for use in PJM's setting of auction parameters.

- *Midwest ISO Capacity Market Enhancements*. Supported the Midwest ISO in developing market design elements for its recently-filed annual locational capacity auctions.

- *Evaluation of the Midwest ISO's Resource Adequacy Construct and Market Design Elements.* For the Midwest ISO, conducted the first major assessment of its new resource adequacy construct. Identified several major successes and a series of recommendations for improvement in the areas of load forecasting, locational resource adequacy, and determination of the target level of reliability. The report incorporates extensive stakeholder input and review, and comparisons to other ISOs' capacity market designs. Continued to consult with Midwest ISO in its work with the Supply Adequacy Working Group on design improvements.

- *Evaluation of Midwest ISO's Demand Response Integration*. For the Midwest ISO, conducted an independent assessment of its progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers to date. Assessed the likelihood of the Midwest ISO's recent "ARC Proposal" to eliminate barriers to participation by curtailment service providers. Made recommendations for potential further improvements to market design elements.

- *Evaluation of Tie-Benefits*. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, allowing reductions in installed capacity margins) on capacity costs, emergency procurement costs, capacity prices, and energy prices. Resulting whitepaper submitted by ISO-NE to the FERC in its filing on tie-benefits.

- *ISO Evaluation of Major Initiatives*. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Also developed guidelines on the kinds of information ISO-NE should provide for major initiatives.

- *Evaluation of ISO-NE Forward Capacity Market (FCM) Results and Design Elements.* With the ISO-NE market monitoring unit, reviewed the performance of the first two forward auctions in ISO-NE's FCM. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor. Resulting whitepaper filed with the FERC and presented to ISO-NE stakeholders.

- *Evaluation of Reliability Pricing Model (RPM) Results and Design Elements.* For PJM, co-led a detailed review of the performance of its forward capacity market. Reviewed the results of the first five forward auctions for capacity. Concluded that the auctions were working and demonstrated success in attracting and retaining capacity, but made more than thirty design recommendations. Recommendations addressed ways to remove barriers to participation, ensuring adequate compensation/penalties, and improving the efficiency of the market. Resulting whitepaper was submitted to the FERC and presented to PJM stakeholders.

- *Evaluation of a Potential Forward Capacity Market.* For NYISO, conducted a benefit-cost analysis of replacing its existing short-term ICAP market structure with a proposed four-year forward capacity market (FCM) design. Evaluation based on stakeholder interviews, the experience of PJM and ISO-NE with their forward capacity markets, and review of the economic literature regarding forward capacity markets. Addressed the following attributes of FCM relative to the existing market: risks to buyers and suppliers, mitigation of market power, implementation costs, and long-run costs. Recommendations used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.

- *RTO Accommodation of Demand Response (DR) for Resource Adequacy*. For the Midwest ISO, helped modify its tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying in detail the practices of other RTOs, and by characterizing the DR resources within the Midwest ISO footprint.

- *Integration of DR into ISO-NE's Energy Markets*. For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the current economic DR programs when they expire in 2010.

- *Integration of DR into Midwest ISO's Energy Markets*. For the Midwest ISO, wrote a whitepaper evaluating the available approaches to incorporating economic DR in energy markets. Assessed the efficiency and the "realistic achievable potential" for each approach. Identified implementation barriers at the state and RTO levels. Recommended changes to business rules to efficiently accommodate curtailment service providers (CSPs).

- *LMP Impacts on Contracts*. For a West Coast client, critically reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated potential incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.

- *RTO Accommodation of Retail Access*. For the Midwest ISO, made recommendations for improving business practices in order to facilitate retail access (and to enable auctions for the supply of regulated generation service). Analyzed the retail access programs in the three restructured states within the Midwest ISO -- Illinois, Michigan, and Ohio. Performed a detailed study of retail accommodation practices in other RTOs, focusing on how they have modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

Transmission Planning and Modeling

- *Benefits of New 765kV Transmission Line.* Analyzed renewable integration and congestion relief benefit of proposed $1.2 billion transmission line in western PJM.
- *Benefit-Cost Analysis of a Major Transmission Project for Offshore Wind.* Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects of the Project on congestion, capacity markets, CO_2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the congestion, production cost, and LMP impacts using the PROMOD model.
- *Analysis of Transmission Congestion and Benefits.* Analyzed the impacts on transmission congestion, California benefits, and Arizona utility impacts of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in 2013 and 2020 considering the recent changes in economic and fuel market conditions, and increased renewable generation requirements throughout the Western Electricity Coordination Council region.
- *Benefit-Cost Analysis of New Transmission.* For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.
- *Benefit-Cost Analysis of New Transmission in the Midwest.* For the American Transmission Company (ATC), supported *Brattle* witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.
- *Transmission Investments and Congestion.* Worked with executives and board of an independent transmission company to develop a "metric" indicating access and congestion-related benefits provided by its transmission investments and operations.
- *Analysis of Transmission Constraints and Solutions.* For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection.

Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.

- *Merchant Transmission Impacts*. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices in Connecticut and Long Island.

- *Security-Constrained Unit Commitment and Dispatch Model Calibration*. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in the Midwest ISO's first allocation of FTRs.

- *Model Evaluation*. Led an internal *Brattle* effort to evaluate commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and Henwood LMP. Performed intensive in-house testing of each model. Evaluated accuracy of model algorithms (*e.g.*, LMP, losses, unit commitment) and ability and ease to calibrate models with backcasts using actual RTO data.

Integrated Resource Planning (IRP)

- *IRP in Connecticut (for 2008)*. For the two major utilities in Connecticut, co-led a comprehensive 10-year evaluation of alternative resource strategies. Strategies were analyzed in the context of the ISO-NE energy and capacity markets across several scenarios spanning a range of plausible futures for uncontrollable external factors such as fuel prices, climate change legislation, economic growth, and generation capital costs. All cases were analyzed using the DAYZER locational market simulation model that contains a detailed representation of the ISO-NE transmission system and mimics the ISO-NE energy market. Metrics that were examined to inform policy recommendations included total resource costs, customer costs, natural gas consumption and emissions. Provided oral testimony before the Connecticut Department of Public Utility Control.

- *IRP in Connecticut (for 2009)*. For the two major utilities in Connecticut, co-led a second annual IRP, this time focused on ten topics: resource adequacy, demand-side management, renewables, transmission, nuclear generation, combined heat and power, environmental regulation/legislation, resource development financing, emerging technologies, and energy security. Provided oral testimony before the Connecticut Department of Public Utility Control.

- *IRP in Connecticut (for 2010)*. For the two major utilities in Connecticut, co-led a third annual IRP, with a major overhaul of the energy, capacity, and renewables (REC) market modeling; an evaluation of alternative resource strategies across multiple scenarios; and an update of the ten policy/technology topics analyzed for the 2009 IRP. Solicited input from numerous stakeholders. Provided oral testimony before the Connecticut Department of Public Utility Control.

- *Analysis of Potential Retirements to Inform Transmission Planning*. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.

- *Resource Planning in Wisconsin*. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Evaluation of Demand Response (DR)

- *DR Potential Study*. For an ISO, analyzed the biggest, most cost-effective opportunities for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.

- *Evaluation of DR Compensation Options*. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted with its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000.

- *Wholesale Market Impacts of Price Responsive Demand (PRD)*. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.

- *Energy Market Impacts of DR*. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.

- *Present Value of DR Investments*. For Pepco Holdings, Inc., analyzed the net present value of its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated the reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the *Brattle*-PJM-MADRI study to estimate the short-term energy market price impact and addressed the long-run equilibrium offsetting effects through several plausible supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Documented findings in a whitepaper submitted to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Valuation of Generation Assets and Contracts

- *Valuation of Generation Assets in ISO-NE*. For several potential buyers of various assets in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to inform considerations of risk.

- *Valuation of Generation Asset Bundle in ISO-NE*. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.

- *Valuation of Generation Asset Bundle in PJM*. For a major retail energy provider preparing to bid for a bundle of generation assets, provided energy and capacity price forecasts and reviewed their valuation methodology. Analyzed the supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the Dayzer model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.

- *Wind Power Development*. For a developer proposing to build a several hundred megawatt wind farm in Michigan, provided a market-based revenue forecast for energy and capacity. Identified gas and CO_2 allowance prices as the key drivers of revenue uncertainty, and evaluated the implications of several detailed scenarios around these variables.

- *Wind Power Financial Modeling*. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.

- *Contract Review for Cogeneration Plant*. For the owner of a large cogeneration plant in PJM, conducted an analysis of revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.

- *Generation Strategy/Valuation*. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.

- *Generation Asset Valuation*. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of plausible scenarios. Identified key uncertainties and risks in the acquisition of such assets.

Energy Contract Litigation

- *Contract Damages*. For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.

- *Contract Damages*. For the same client and contract described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.

- *Contract Termination Payment*. For an independent power producer, supported expert testimony on damages resulting from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's operating characteristics and costs. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

RTO Participation and Configuration

- *Market Impacts of RTO Seams*. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the Midwest ISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across regional transmission organization (RTO) seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with the Midwest ISO to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.

- *Analysis of RTO Seams*. For a Wisconsin utility in a complaint proceeding before the FERC, assisted expert witness providing testimony regarding (1) the inadequacy of MISO and PJM's current efforts to improve inter-RTO coordination, and (2) the large net economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO and PJM in energy prices and in shadow prices of reciprocal coordinated flow gates. Analyzed results of MISO and PJM's market simulation models.

- *RTO Participation*. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Analysis of Market Power

- *Vertical Market Power.* Before the NYPSC, examined whether the merger between National Grid and KeySpan potentially created incentives to exercise vertical wholesale market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.

- *Market Monitoring and Market Power Mitigation.* For the PJM Interconnection, assessed their market mitigation practices and co-authored a whitepaper "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets" (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).

Tariff and Rate Design

- *Transmission Tariffs.* For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.

- *Retail Rate Riders.* For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.

- *Rate Filings.* For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- *Evaluation of Cogeneration Venture.* For an unregulated division of a utility holding company, led the financial evaluation of a nascent venture to build and operate cogeneration facilities on customer sites. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.

- *Strategic Sourcing.* For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with top executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Wrote RFPs and developed negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.

- *M&A Advisory*. For a major European utility wanting to expand into U.S. markets and enhance their trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed the experience of acquirers in other M&A transactions. Advised client not to acquire their target, just when it was nearing its peak in market value (just prior to collapse).

- *Marketing Strategy*. For a large power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the potential value client could bring to each potential customer. Worked directly with company president to translate findings into a marketing strategy.

- *Distributed Generation (DG) Market Assessment*. For the unregulated division of an integrated utility, performed a market assessment of established and emerging DG technologies. Projected future market sizes across multiple market segments in the U.S. Concluded that DG presented little immediate threat to the client's traditional generation business, and that it presented few opportunities that the client was equipped to exploit.

- *Fuel Cells*. For a European fuel cell component manufacturer, acted as a technology and electricity advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY AND REGULATORY FILINGS

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies re: the Public Policy, Congestion Relief, and Economic Benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the Public Policy, Reliability, Congestion Relief, and Economic Benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

"Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Ahmad Faruqui at *The Brattle Group,* with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 "Integrated Resource Plan for Connecticut" (see below), June 30, 2009.

2009 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

"Informational Filing of the Internal Market Monitoring Unit's Report Analyzing the Operations and Effectiveness of the Forward Capacity Market," prepared by Dave LaPlante and Hung-po Chao of ISO-

NE with Sam Newell, Metin Celebi, and Attila Hajos of *The Brattle Group*, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 "Integrated Resource Plan for Connecticut" and "Supplemental Reports" (see below), September 22-25, 2008.

"Integrated Resource Plan for Connecticut," co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, D. Murphy, and J. Wharton, January 2, 2008. *Supplemental Report* co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, "Planning Analysis of the Paddock-Rockdale Project," report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

ARTICLES AND PRESENTATIONS

"Integrated Resource Planning in Restructured States," presentation at EUCI conference on "Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes," White Plains, NY, October 17, 2011.

"Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15," report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM," report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Demand Response Gets Market Prices: Now What?" NRRI teleseminar panelist, June 9, 2011.

"DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" *Public Utilities Fortnightly*, November 2010.

"Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements," report prepared for Midwest ISO, January 2010 (with K. Spees and A. Hajos).

"Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design," report prepared for Midwest ISO, January 2010 (with A. Hajos).

"Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market," whitepaper written for the NYISO and submitted to stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).

"Fostering Economic Demand Response in the Midwest ISO," whitepaper written for the Midwest ISO, December 30, 2008 (with R. Earle and A. Faruqui).

"Review of PJM's Reliability Pricing Model (RPM)," report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).

"Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," *Energy*, Vol. 1, 2008, *The Brattle Group* (with M. Chupka and D. Murphy).

"Enhancing Midwest ISO's Market Rules to Advance Demand Response," report written for the Midwest Independent System Operator, March 12, 2008 (with R. Earle).

Before the PJM Board of Directors and senior level representatives at PJM's General Session, Panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.

"Resource Adequacy in New England: Interactions with RPS and RGGI," Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.

"Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns," Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.

"The Power of Five Percent," *The Electricity Journal*, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).

"Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets," Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes and others).

"Evaluating the Economic Benefits of Transmission Investments," EUCI's Cost-Effective Transmission Technology Conference, Nashville, May 3, 2007 (with J. Pfeifenberger, presenter).

"Valuing Demand-Response Benefits in Eastern PJM," *Public Utilities Fortnightly*, March 2007 (with J. Pfeifenberger and F. Felder).

"Quantifying Demand Response Benefits in PJM," study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).

"Quantifying Demand Response Benefits in PJM," PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.

"Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," *Energy*, Vol 2, 2006, *The Brattle Group* (with J. Pfeifenberger).

"Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

"Who Will Pay for Transmission," CERA Expert Interview, Cambridge, MA, January 15, 2004.

"Reliability Lessons from the Blackout; Transmission Needs in the Southwest," presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.

"Effect of Cross Sound Cable," *CERA Alert*, October 24, 2003 (with H. Stauffer and G. Mukherjee).

"Application of the 'Beneficiary Pays' Concept," presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

Exhibit 2 to Attachment D

2011 CONE Study

The Brattle Group

Cost of New Entry Estimates For Combustion-Turbine and Combined-Cycle Plants in PJM

August 24, 2011

Kathleen Spees
Samuel A. Newell
Robert Carlton
Bin Zhou
Johannes P. Pfeifenberger
The Brattle Group

with
CH2M HILL
Wood Group Power Operations

Prepared for

PJM Interconnection, L.L.C.

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EXECUTIVE SUMMARY

This report documents our study of the gross Cost of New Entry ("CONE") for combustion turbine ("CT") and combined-cycle ("CC") power plants with a target online date of June 1, 2015, consistent with the 2015/16 delivery year in PJM's capacity market. We prepared this study in cooperation with CH2M HILL, a major engineering procurement, and construction company with extensive experience in the design and construction of power plants, and Wood Group, a power plant operation and maintenance ("O&M") service provider.

Gross CONE includes both the capital and ongoing fixed operating costs required to build and operate a new plant. We present these estimates for consideration by PJM Interconnection and stakeholders as they update the administrative CONE parameters for PJM's capacity market, the Reliability Pricing Model ("RPM"). The CT CONE parameter is used to define points of the Variable Resource Requirement (VRR) curve; both CC and CT CONE parameters are used for calculating offer price screens under the Minimum Offer Price Rule ("MOPR") for new generation offering capacity into RPM. We provide separate CT and CC CONE estimates for each of the five administrative CONE Areas in PJM.

Table 1 shows our recommended CONE for gas CT plants in each CONE Area based on levelized plant capital costs and annual fixed operation and maintenance ("FOM") costs for the 2015/16 delivery year. The table shows the major components of the CONE calculation including overnight costs, plant net summer installed capacity ("ICAP"), annual ongoing fixed O&M costs, and the after-tax weighted-average cost of capital ("ATWACC"). Our CONE estimates are presented on a "level nominal" basis (*i.e.*, equal payments over the plant's economic life) as well as on a "level real" basis (*i.e.*, payments that start lower but increase with inflation over time). As we explain in our concurrent report, Second Performance Assessment of PJM's Reliability Pricing Model, August 26, 2011 ("2011 RPM Report"), we recommend transitioning toward using a level-real CONE for MOPR purposes; for defining the VRR curve, we also recommend transitioning to level-real contingent on the implementation of several other recommendations.

Our estimates differ by CONE area due to differences in plant configuration assumptions, differences in labor rates, and other locational differences in capital and fixed costs. In each CONE area, except for the Rest of RTO area, all plants are configured with dual fuel. In addition, the CT plants are fitted with Selective Catalytic Reduction ("SCR") in each location except in Dominion, where the current Ozone attainment status does not yet require an SCR. We also provide costs for plants with dual-fuel capability and SCRs in each Area in case future developments necessitate such investments.

The Eastern Mid-Atlantic Area Council ("Eastern MAAC" or "EMAAC") and Western MAAC regions have the highest CONE estimates at $112/kW-year ($307/MW-day) and $109/kW-year ($298/MW-day) respectively on a level real basis. The Southwest MAAC and Rest of RTO areas are somewhat lower, both at $103/kW-year ($283/MW-day), primarily because of the non-union labor availability in Southwest MAAC and the lack of dual-fuel capability in the Rest of RTO region. The lowest CONE estimate is in Dominion at $93/kW-year ($254/MW-day), due to lower non-union labor rates and avoiding an SCR. Avoiding an SCR in Dominion reduces overnight capital costs by approximately $24 million, while avoiding dual-fuel capability in the Rest of RTO area reduces capital costs by approximately $19 million. These corresponding level-nominal costs are shown in Table 1.

Table 1 also shows the CONE estimates Power Project Management ("PPM") provided to PJM in 2008. PJM stakeholders agreed to use those estimates for setting points on the VRR curve by discounting them by 10 percent and then escalating them with the Handy-Whitman Index. To facilitate a more direct comparison of the PPM study to ours, we present the PPM results without discount, and inflation adjusted to 2015 dollars. As such, our level-nominal estimates are $19 to 23/kW-year ($53 to 62/MW-day) lower than the PPM estimates in the three CONE Areas reported. Our estimates are lower primarily due to reductions in equipment, materials, and labor costs since 2008 relative to inflation, as well as economies of scale associated with the larger size of the GE 7FA.05 turbine compared to the previously examined GE7FA.03 turbine model.

Finally, Table 1 also shows the CONE PJM has applied in its recent auction for the 2014/15 delivery year, escalated for one year of inflation to represent 2015/16 dollar values.

Table 1
Recommended Gas CT CONE for 2015/16

CONE Area	**Total Plant Capital Cost**	**Net Summer ICAP**	**Overnight Cost**	**Fixed O&M**	**After-Tax WACC**	**Levelized Gross CONE**		**PJM 2014/15 CT CONE**
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$308.3	390	$791.2	$15.7	8.47%	$112.0	$134.0	$142.1
2 Southwest MAAC	$281.5	390	$722.6	$15.8	8.49%	$103.4	$123.7	$131.4
3 Rest of RTO	$287.3	390	$737.3	$15.2	8.46%	$103.1	$123.5	$135.0
4 Western MAAC	$299.3	390	$768.2	$15.1	8.44%	$108.6	$130.1	$131.4
5 Dominion	$254.7	392	$649.8	$14.7	8.54%	$92.8	$111.0	$131.5
Power Project Management, LLC 2008 Update								
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)								
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%	n/a	$154.4	n/a
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%	n/a	$142.8	n/a
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%	n/a	$146.1	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Dominion estimate excludes an SCR; with SCR CONE increases to $100.8/kW-year level real and $120.6/kW-year level nominal.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $110.7/kW-year level real and $132.5/kW-year level nominal.

PPM's estimates shown here were discounted by 10% in settlement and escalated at the Handy-Whitman Index for setting the administrative gross CONE parameters over the 2012/13 through 2014/15 delivery years PJM Interconnection, L.L.C. (2011d), p. 10; Power Project Management (2008).

PPM's numbers are escalated according to historical inflation over 2008-2011 and at 2.5% inflation rate over 2011-2015, see Federal Reserve Bank of St. Louis (2011) and Section VI.A.

Table 2 shows our recommended 2015/16 CONE for gas CC plants. These estimates are compared to the most recent estimates developed by Pasteris Energy for PJM in 2011. In each location, the gas CC plant is configured with an SCR. The plants have dual–fuel capability in all CONE Areas except in the Rest of RTO Area. Avoiding dual-fuel capability in the Rest of RTO Area reduces capital costs by approximately $18 million.

Eastern MAAC has the highest CC CONE at $141/kW-year ($385/MW-day) on a level real basis, while Rest of RTO and Western MAAC are a bit lower, both at $135/kW-year ($370/MW-day). Southwest MAAC and Dominion have the lowest CONE estimates at $123/kW-year ($338/MW-day) and $120/kW-year ($329/MW-day) respectively, primarily due to non-union labor rates in those locations. Our estimates are $6 to 12/kW-year ($17 to 32/MW-day) below the Pasteris Energy CONE estimates on a level-nominal basis primarily due to a higher ICAP rating. Our higher plant ICAP rating reflects the larger size of the GE 7FA.05 turbine relative to the GE7FA.04 turbine model examined by Pasteris, as well as the greater duct firing capability in the plant we examine. Table 2 also shows the CC CONE value PJM has utilized for the 2014/15 delivery year, inflation adjusted to 2015/16 dollar values.

Table 2
Recommended Gas CC CONE for 2015/16

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CC CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$621.4	656	$947.8	$16.7	8.47%	$140.5	$168.2	$179.6
2 Southwest MAAC	$537.4	656	$819.6	$16.6	8.49%	$123.3	$147.6	$158.7
3 Rest of RTO	$599.0	656	$913.7	$16.0	8.46%	$135.5	$162.2	$168.5
4 Western MAAC	$597.4	656	$911.2	$15.8	8.44%	$135.2	$161.8	$158.7
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8	$158.7
Pasteris 2011 Update								
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)								
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%	n/a	$179.6	n/a
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%	n/a	$158.7	n/a
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%	n/a	$168.5	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $138.9/kW-year level real and $136.3/kW-year level nominal.

Pasteris Energy's 2011 CONE estimates were used as the basis for the CC CONE estimate for the 2014/15 delivery year, see Pasteris Energy (2011), pg. 55.

Pasteris Energy's numbers are escalated at 2.5% inflation rate, see and Section VI.A.

I. BACKGROUND

A. STUDY OBJECTIVE

The Cost of New Entry ("CONE") is an administrative parameter used in PJM's capacity market, the Reliability Pricing Model ("RPM"), with CONE values defined separately in each of five CONE Areas.[1] The CONE parameter for a gas combustion turbine ("CT") is used as an input for calculating points on the Variable Resource Requirement ("VRR") curve.[2] The CONE parameters for a gas combined cycle ("CC") as well as a gas CT are used in calculating offer price screens under the Minimum Offer Price Rule ("MOPR") for new generation offering capacity into RPM.[3]

As a requirement of the Open Access Transmission Tariff ("OATT"), PJM is required to review the CONE parameter for the delivery year starting June 1, 2015 and every third year after that.[4] Between these triennial reviews, CONE is updated annually according to the Handy-Whitman Index. We were asked to assist PJM and stakeholders in this triennial review by developing CONE estimates for new gas CT and CC plants in each of the five CONE Areas. In this study, we define the gas CT and CC reference technologies for each CONE Area and estimate plant capital and other fixed costs for each plant.

B. ANALYTICAL APPROACH

For a particular reference technology, CONE is made up of plant capital costs, which must be levelized to produce an annual cost, plus annual fixed operation and maintenance ("FOM") costs. Our analytical starting point is the selection of the most economic reference technologies and feasible siting locations in each CONE Area. For each CC and CT in each area, we characterized the reference plants by size, turbine technology, configuration, and typical site characteristics. Key configuration variables include NO_x controls, duct firing and other power augmentation, cooling systems, dual-fuel capability, and gas compression. We selected specific characteristics based on our analysis of the predominant practice among recently-developed plants; our analysis of technologies, regulations, and infrastructure; and guidance from engineering sub-contractors. Key site characteristics include proximity to high voltage transmission infrastructure and interstate gas pipelines, siting attractiveness as indicated by units recently built or currently under construction, and availability of vacant industrial land. Our analysis for selecting plant locations and technical specifications is presented in Section II. A summary of the resulting technical and site characteristics of the identified reference technologies is presented in Section III.

To develop estimates of plant proper capital costs for the reference gas CT and CC plants in each CONE area, *The Brattle Group* sub-contracted with CH2M HILL Engineers, Inc. CH2M HILL

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1 PJM (2011b), p. 2278
2 PJM (2011b), p. 2280.
3 PJM (2011b), pp. 2297-2300.
4 PJM (2011b), p. 2280.

is an engineering, procurement, and construction ("EPC") company with extensive experience in the design and construction of gas CT and CC plants. They developed capital and construction cost estimates using the same data and models they use to support their bids for actual projects. The results of their analysis are presented in Section IV.A with detailed supporting documentation for the CT and CC technologies in Appendices A and B. Separately, we estimated several plant owner's costs, as described in Section IV.B. Given the combined, comprehensive costs of each reference plant, we estimated levelized annual capital carrying costs using standard financial techniques, as described in Section VI.

The Brattle Group also sub-contracted with Wood Group Power Operations, Inc. to estimate fixed and variable O&M costs for the reference CT and CC plants. Wood Group has extensive experience providing outsourced O&M services to owners of generation plants, and has previously provided O&M estimates for PJM in previous CONE studies. The results of their analysis are presented in Sections IV.B.6, V.C, and V.E, with additional supporting details included in Appendix C.

We separately estimated several other fixed annual operations costs that will be incurred over the plant life but that are not covered under an O&M services provider's scope. Our analyses were further informed by a number of conversations with plant operators and developers.

II. DETERMINATION OF REFERENCE TECHNOLOGY

A. Approach to Determining Reference Technology Characteristics

We determined the reference technology primarily using a "revealed preferences" approach, in order to assess the market's determination of the most attractive technology for investment. The advantage of this approach is that it is informed by the choices that actual developers found to be most feasible and economic. However, because technologies and environmental regulations continue to evolve, we supplement this "revealed preference" approach with guidance from CH2M HILL and with additional analysis of underlying economics, regulations, and infrastructure.

As the basis for determining most of the selected reference technology specifications, we closely examined all gas CT and CC plants developed in PJM and the U.S. since 2002, including plants currently under construction. We characterized these plants by size, turbine technology, plant configuration, NO_X controls and emissions rates, duct firing, dual-fuel capability, and cooling systems.

B. Siting Plant Locations within Each CONE Area

The Open Access Transmission Tariff ("OATT") requires a separate Gross CONE parameter in each of five CONE Areas as summarized in Table 3.[5]

[5] PJM Interconnection, L.L.C. (2011b), p. 2278.

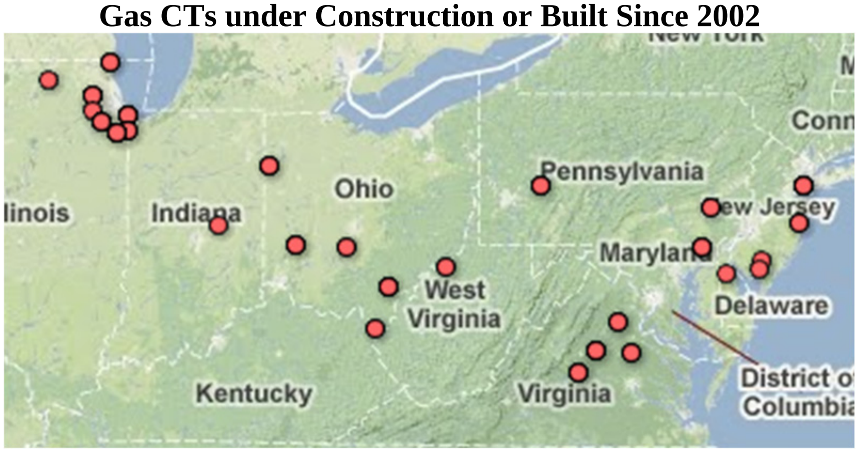
Table 3
CONE Areas

CONE Area	Transmission Zones	States
1 Eastern MAAC	AECO, DPL, JCPL, PECO, PSEG, RECO	NJ, MD, DE
2 Southwest MAAC	BGE, PEPCO	MD, DC
3 Rest of RTO	AEP, APS, ATSI, ComEd, DAY, DEOK, DQL	WV, VA, OH, IN, IL, KY, TN, MI
4 Western MAAC	MetEd, Penelec, PPL	PA
5 Dominion	Dominion	VA, NC

Sources and Notes:
PJM Interconnection, L.L.C. (2011b), p. 2284.
PJM Interconnection, L.L.C. (2011c)
CONE Areas fall on exact transmission zone boundaries but not on exact state boundaries.

We conducted a siting evaluation to select a specific county to use as the cost estimate basis for the reference plant within each CONE Area. Our primary criteria for identifying feasible and favorable locations were: (1) the availability of high voltage transmission infrastructure; (2) the availability of a major gas pipeline; (3) siting attractiveness as indicated by units recently built or currently under construction; and (4) the availability of vacant industrial land.[6] Figure 1 and Figure 2 show the locations of gas CT and CC units built in PJM since 2002.

Figure 1
Gas CTs under Construction or Built Since 2002



Sources and Notes:
Plant locations from Ventyx (2011). Mapped with Google Maps (2011).
Map shows 27 different plants built since 2002.

[6] Plant locations from Ventyx (2011), transmission infrastructure from PJM (2008), gas pipeline locations from Platts (2011), and vacant industrial land sales postings from Loopnet (2011).

Figure 2
Gas CCs under Construction or Built Since 2002

Sources and Notes:
Plant locations from Ventyx (2011). Mapped with Google Maps (2011).
Map shows 25 different plants built since 2002, and excludes cogeneration facilities.

Table 4 shows the counties we selected in our siting exercise along with the transmission zone, infrastructure available, the selected generator step-up ("GSU") high side-voltage, and the gas pipelines available in that county. The Eastern MAAC, Western MAAC, and Dominion CONE Areas each have multiple counties that meet our selection criteria, with several recent projects having been developed along corridors with major gas pipelines and with substantial electric infrastructure. In these areas, we selected locations with more recent projects where possible, recognizing that there are multiple locations with equally good siting opportunities. The Rest of RTO CONE Area is the largest geographically, spanning many states and containing a large number of recent builds. We selected a county near Chicago because this location has the highest concentration of recent projects.

Our siting selection for the Southwest MAAC CONE Area is less certain because there are no gas-fired generation projects recently built or under construction. In order to select a feasible site, we used additional criteria to supplement our requirement of electric and gas infrastructure availability. We selected Charles County over other counties because of a greater availability of vacant industrial land relative to the more densely developed locations along the Transco and Columbia pipelines.[7] Further, the only permitted prospective gas plant in the CONE Area is in Charles County, the 640 MW CPV St. Charles gas CC project.[8] The most recently built gas-fired facility in Southwest MAAC is the 230 MW Panda Cogeneration project, built in 1996 in the neighboring Prince Georges County immediately across the county line. We did not select this county due to the relatively longer gas interconnection lateral that would be required.[9]

7 For example, few vacant industrial properties are listed for sale or have been recently transacted in Howard or Montgomery counties in Maryland. In the past 2 years, the only transaction in Howard or Montgomery county for over 20 acres of vacant industrial land was located in Elkridge, Maryland, in Howard county, see Maryland Assessment Records (2011).

8 Ventyx (2011).

9 Ventyx (2011) and Platts (2011).

Table 4
Selected Locations for Reference Plants

CONE Area and County	Zone	Transmission Infrastructure Available *(kV)*	Transmission GSU High-Side Voltage *(kV)*	Gas Pipelines
1 Middlesex, NJ	JCPL	130, 230, 500	230	Transco, Texas Eastern
2 Charles County, MD	PEPCO	230, 500	230	Dominion Cove Point
3 Will, IL	COMED	138, 345	345	ANR, Natural (NGPL), Midwestern, Guardian/Vector
4 Northampton, PA	PPL	138, 230, 500	230	Transco, Columbia
5 Fauquier, VA	DOM	115, 230, 500	230	Transco, Columbia, Dominion

Sources and Notes:
Transmission infrastructure information from PJM (2008).
Gas pipeline information from Platts (2011).

C. PLANT CONFIGURATION AND SIZE

We selected plant size and configuration based on a review of gas CT and CC projects currently under construction or built in PJM since 2002. Table 5 shows the amount of gas CT capacity built in PJM since 2002 for each plant size bracket. The plant size refers to the total plant size including all CT units installed at each site, with most plants including multiple turbine units. We selected a target plant size of 400-500 MW, which is the dominant size for newly-built CT plants in PJM, representing 2.8 of the 7.5 GW of PJM simple-cycle turbines built or under construction since 2002. This is the most common plant size range in the Rest of RTO and Dominion CONE Areas, representing three of the 13 recently built plants in the Rest of RTO Area and both of the two plants recently-built in Dominion. The Eastern MAAC CONE Area had three recently built plants, with the middle-sized one in the 400-500 MW range. Although there no sizeable recent projects in the Southwest MAAC and Western MAAC CONE Areas, we use the same 400-500 MW gas CT plant range for these areas.

Table 5
PJM Gas CT Plants under Construction or Built Since 2002

CONE Area	< 100 *(MW)*	100-200 *(MW)*	200-300 *(MW)*	300-400 *(MW)*	400-500 *(MW)*	500-600 *(MW)*	600-700 *(MW)*	700-800 *(MW)*	800-900 *(MW)*	Total *(MW)*
1 Eastern MAAC	48	0	0	326	462	0	639	0	0	**1,474**
2 Southwest MAAC	0	0	0	0	0	0	0	0	0	**0**
3 Rest of RTO	80	156	888	664	1,351	1,088	0	0	825	**5,052**
4 Western MAAC	10	0	0	0	0	0	0	0	0	**10**
5 Dominion	0	0	0	0	947	0	0	0	0	**947**
Total	**138**	**156**	**888**	**990**	**2,760**	**1,088**	**639**	**0**	**825**	**7,484**

Sources and Notes:
Plant information from Ventyx (2011).
Table includes only new plants, not additions to existing plants.

Similarly, we determined the predominant configuration for gas CC plants based on a survey of PJM plants currently under construction or built since 2002. Table 6 shows the amount of gas CC capacity built for each plant size and configuration. As the table shows, the dominant size and configuration has been 500-700 MW in a 2x1 configuration.[10] As we discuss in Sections II.D and II.F, we specified a slightly larger 2x1 plant consistent with the increased size of the new 7FA.05 turbine model.

Table 6
PJM Gas CC Plants under Construction or Built Since 2002

	< 300 (MW)	300-500 (MW)	500-700 (MW)	700-900 (MW)	900-1100 (MW)	1100-1300 (MW)	Total (MW)
2 x 1	0	0	$\boxed{5,593}$	0	0	0	**5,593**
2 x 2	0	0	573	0	0	0	**573**
3 x 1	245	0	556	2,386	0	0	**3,187**
4 x 2	0	0	0	0	1,080	3,725	**4,805**
4 x 4	0	0	0	0	0	1,140	**1,140**
6 x 2	0	0	0	0	935	1,130	**2,065**
Total	**245**	**0**	**6,723**	**2,386**	**2,015**	**5,995**	**17,364**

Sources and Notes:
Plant information from Ventyx (2011).
Table includes only new plants, not additions to existing plants.

D. TURBINE MODEL

We determined the predominant turbine models by reviewing the turbines installed in gas-fired plants in the United States since 2002. Table 7 shows the total installed capacity and costs of the most widely-used turbines used in gas CT plants since 2002.[11] The most commonly installed turbine since 2002 in simple-cycle configuration has been the GE Frame 7FA model turbine followed closely in terms of installed MW by the GE 7EA, although for our purposes we did not select that smaller turbine model because the 7FA has both a lower heatrate and a lower cost per unit of power output.

We also note that the 7FA turbine model has changed substantially during the period from 2002 to the 2015 installation date that we use for our turbine model. The 7FA.03 model available in 2003 had a nameplate capacity rating of 175 MW, while the 7FA.04 model had a higher rating of 183 MW. The new 7FA.05 model that is now available and will replace the 7F4.04 has a higher rating of 211 MW.[12] The updated 7FA.05 model also has a substantially improved heatrate.[13]

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10 Also note that the second-most common configuration is 4x2, or two 2x1 units at a single plant.
11 We use the Ventyx Energy Velocity database to identify the installed MW and turbine type for each technology. The database does not identify the turbine technology for all turbines.
12 See GE (2009), p. 7.
13 The efficiency of the 7FA.05 is 1.4 percentage points higher than the 7FA.03 model on an LHV basis. See GE (2009), p. 5.

Table 7
Gas CT Units Installed by Turbine Type in the U.S. Since 2002

Turbine Model	**Installed Since 2002** *(MW)*	*(count)*	**Cost** *($/kW)*
General Electric Co-MS7001FA GT	11,571	87	$232
General Electric Co-MS7001EA	10,115	119	$266
Siemens Power Generation Inc-SGT6-5000F	3,120	15	$226
General Electric Co-LM6000PC Sprint	2,805	55	$319
General Electric Co-LM6000PC	2,596	59	$334
General Electric Co-GE LM6000	2,451	57	$340
General Electric Co-LMS100PB-DLE2	1,881	19	$296
Pratt & Whitney-FT8 Twinpac	1,860	30	$298
General Electric Co-LMS100PA-SAC	1,854	18	$300
Pratt & Whitney-FT8 SwiftPac	976	16	n/a

Sources and Notes:
Installed MW and number of units by turbine model from Ventyx (2011). This database is not completely comprehensive in identifying turbine model, with about 80% of the total MW installed since 2002 being identified by turbine type.
Turbine cost (excluding balance of plant) from *Gas Turbine World* (2010).

Similarly for gas CC plants, Table 8 shows the amount of capacity installed by turbine type since 2002, as well as cost information based on a typical configuration from *Gas Turbine World*. Like the gas CT plant, we chose the GE 7FA turbine because of its predominance and low capital costs compared with other turbines.

Table 8
Gas CC Units Installed by Turbine Type in the U.S. Since 2002

Turbine Model	**Installed Since 2002** *(MW)*	*(Count)*	**Cost** *($/kW)*
General Electric Co-MS7001FA GT	32,940	180	$473
Siemens Power Generation Inc-501FD	11,232	54	$499
Mitsubishi Heavy Industries-M501G	5,874	22	$504
Siemens Power Generation Inc-SGT6-6000G	1,335	5	n/a
General Electric Co-MS7001FB	1,260	7	$466
Mitsubishi Heavy Industries-M501F	925	5	$537
General Electric Co-MS7001EA	765	9	$524
Siemens Power Generation Inc-V84.2	452	4	$459
General Electric Co-LM6000PC Sprint	204	4	n/a
General Electric Co-LM6000PD Sprint	172	4	n/a

Sources and Notes:
Installed MW by turbine model from Ventyx (2011). This database is not completely comprehensive in identifying turbine model, with 35% of the total MW installed since 2002 being identified by turbine type.
Unit cost (including steam turbine but excluding balance of plant) assumes a typical configuration and steam turbine, from *Gas Turbine World* (2010).

E. Combined-cycle Cooling System

For the reference combined-cycle plant, we assumed a closed-loop circulating water cooling system with a multiple-cell mechanical draft cooling tower, based on the predominance of cooling towers among new CCs and CH2M HILL's recommendation. Among the 15 CC units installed in PJM since 2002 and reporting cooling system data, 13 have cooling towers while 2 have air cooling or once-through cooling systems.[14]

F. Duct Firing and Power Augmentation

For the reference CC plant, we included duct firing capability, consistent with predominant practice among projects in PJM and elsewhere. We determined that a cost-effective amount of duct firing to include was 74 MW at 92 °F (76 MW at 59 °F) based on guidance from CH2M HILL, and consultation with GE representatives. According to CH2M and GE, this quantity of duct firing is consistent with 7FA.05 2x1 projects currently being developed.

For CCs and CTs, we also evaluated additional power augmentation options by comparing the capital costs and incremental output available if investing in each option. Table 9 and Table 10 compare inlet evaporative cooling to inlet chilling and to no power augmentation for both gas CT and CC plants. These cost and performance metrics were calculated by CH2M HILL using GE software, and while self-consistent, represent rough approximations of equipment and balance of plant ("BOP") cost components without considering detailed locational, materials escalation, or other engineering cost factors.

[14] Ventyx (2011).

We selected inlet evaporative cooling for power augmentation for both plant types because it increases their output substantially for only a small increase in cost. The slightly higher output that inlet chilling could provide does not appear cost-effective for the incremental cost, as indicated by the relatively higher cost per unit of output than that of the overall plant.

Table 9
Power Augmentation Comparison for Gas CT

	Total Cost ($m)	Capacity ISO Conditions (MW)	Capacity Summer Conditions (MW)	Incremental Output ISO Conditions (MW)	Incremental Output Summer Conditions (MW)	Incremental Costs ISO Conditions ($/kW)	Incremental Costs Summer Conditions ($/kW)
None	$192	412	377				
Inlet Evaporative Cooling	**$193**	**420**	**395**	**8**	**18**	**$84**	**$39**
Inlet Chilling	$205	425	417	5	22	$2,306	$555

Sources and Notes:
CH2M HILL (2011), using GE software.
International Organization for Standardization (ISO) conditions are 59 °F and 60% relative humidity.
Summer conditions are 90 °F and 53% relative humidity.

Table 10
Power Augmentation Comparison for Gas CC

	Total Cost ($m)	Capacity ISO Conditions (MW)	Capacity Summer Conditions (MW)	Incremental Output ISO Conditions (MW)	Incremental Output Summer Conditions (MW)	Incremental Costs ISO Conditions ($/kW)	Incremental Costs Summer Conditions ($/kW)
None	$449	618	550				
Inlet Evaporative Cooling	**$450**	**627**	**589**	**10**	**39**	**$62**	**$16**
Inlet Chilling	$463	633	613	5	24	$2,640	$580

Sources and Notes:
CH2M HILL (2011), using GE software.
International Organization for Standardization (ISO) conditions are 59 °F and 60% relative humidity.
Summer conditions are 90 °F and 53% relative humidity.

G. NO_X CONTROLS

In determining the NO_X controls that will be required for each new unit to pass its new source review ("NSR") and receive an operating air permit, we considered the following: controls installed by recently developed gas-fired units, tightening standards due to recent and imminent EPA regulations, special permitting considerations in each plant location, and special technological considerations for each plant configuration we selected.

Table 11 contains a summary of NO_X control equipment on units built in PJM since 2002. The data is displayed separately for single-fuel and dual-fuel gas CCs and CTs, and by turbine type. The table shows that there are several NO_X controls that are consistently required under NSR for all units regardless of locational air permitting considerations. The table shows that all 7FA units in either CT or CC configuration are equipped with dry low-NO_X burners, as expected because dry-low NO_X burners are part of the 7FA turbine model design. All 7FA CC and CT units with dual-fuel capability are also equipped with water injection for NO_X control for use during firing on distillate.[15] Most recently built CCs installed with 7FA or non-7FA turbines have also been fitted with Selective Catalytic Reduction ("SCR") controls.

Table 11
Number of Turbines with NO_X Control Equipment in PJM Units Installed Since 2002

	Single Fuel		Dual Fuel	
	All Turbine Models *(count)*	**7FA Turbines** *(count)*	**All Turbine Models** *(count)*	**7FA Turbines** *(count)*
Gas CT				
Dry Low NO_X Burners	39	7	23	17
Selective Catalytic Reduction	16	0	1	0
Water Injection	20	1	24	17
Total	**55**	**7**	**24**	**17**
Gas CC				
Dry Low NO_X Burners	17	11	10	10
Selective Catalytic Reduction	18	11	13	10
Water Injection	0	0	9	9
Total	**18**	**11**	**13**	**10**

Sources and Notes:
Ventyx (2011).

The data in Table 11 indicate that 7FAs in simply cycle mode have not installed SCRs. However, this does not prove that SCRs will be infeasible or unneeded in 2015 as environmental regulations continue to tighten. Many recently-built non-7FA CTs have been fitted with an SCR. Although no recently-built 7FA CTs have been fitted with SCRs, one earlier unit was fitted with this technology, however, it is not located in PJM.[16] There are two reasons that few SCRs have been required on 7FAs in simple-cycle configuration. First, the 7FA has a relatively lower emissions rate than most other turbines even without an SCR because of its dry low-NO_X burning technology. The 7FA.05 NO_X emissions rate is 9 ppm without an SCR (2 ppm with an SCR), while many emissions standards have been developed based on the maximum allowed emissions rates of 25 ppm for gas CTs.[17]

Second, the temperature of 7FA turbine exhaust is very high, which requires the exhaust to be diluted through tempering air fans to avoid damaging the SCR equipment. Adding a hot SCR to a 7FA in simple-cycle configuration incurs a higher cost than adding a typical SCR to a turbine with a lower exhaust temperature. Despite the higher costs, CH2M HILL has confirmed with three potential suppliers of hot SCR controls that they have received inquiries and budget requests for hot SCRs on large F-class turbines for projects currently under development in the

15 Confirmed based on guidance from CH2M HILL and GE representatives.
16 The Rowan plant in Salisbury, North Carolina built in 2001, see Ventyx (2011).
17 See for example, New Jersey State Department of Environmental Protection (2011), pg. 29, as well as the Ozone Transport Commission (2010), pg. 4, both stipulate a maximum CT emissions rate of 25 ppm.

U.S. In particular, the Mirant Marsh Landing Generating station in Contra Costa County, CA will be fitted with a hot SCR and is currently expected to complete construction in 2013.[18]

The determination of whether a particular CT project will require an SCR in order to receive an air permit will be determined based on the outcome of the new source review ("NSR"), as determined on a case-by-case basis for each plant. The NSR is overseen by a state regulatory agency in most cases and is guided by the current status in meeting the National Ambient Air Quality Standards ("NAAQS"). In locations that are in attainment of the NAAQS, the NSR is conducted under the Prevention of Significant Deterioration ("PSD") rules that require units to install the Best Available Control Technology ("BACT") in order to obtain approval. In locations that are designated as non-attainment of the NAAQS, the Non-Attainment NSR ("NNSR") rule require units to apply the more stringent Lowest Achievable Emissions Rate ("LAER") standard.[19] In locations that have previously been in non-attainment and are currently in "maintenance" of the NAAQS, the NSR will generally continue to impose a stringent control technology standard in order to maintain air quality pollutant levels.

The attainment status for ozone, for which NO_X is a precursor, is the most relevant for determining whether an SCR will be required. Table 12 shows the current 8-hour ozone attainment status based on current NAAQS. The EPA is currently in the process of tightening its NAAQS for ozone with new standards to be ruled soon after the publication of this study that will likely bring more areas into nonattainment.[20] Additional regulatory uncertainty regarding the need for an SCR is also introduced by the Cross-State Air Pollution Rule ("CSAPR") finalized on July 6, 2011 that will require PJM states to revise their SIPs in order to help meet ozone NAAQS not only in their own states but also in specific downwind locations in other states.[21]

Table 12
8-Hour Ozone Attainment Status

CONE Area		County	Ozone Attainment Status
1	Eastern MAAC	Middlesex, NJ	Nonattainment
2	Southwest MAAC	Charles County, MD	Nonattainment
3	Rest of RTO	Will, IL	Nonattainment
4	Western MAAC	Northampton, PA	Maintenance
5	Dominion	Fauquier, VA	Attainment

Sources and Notes:
EPA (2011a).

After considering the regulatory and technological factors described above, we believe the most likely outcome of a 7FA simple-cycle NSR for an online date of June 1, 2015 is that the project will be required to be fitted with an SCR if it is currently in a non-attainment or maintenance area for ozone, but that it will not need an SCR if it is in an attainment area. Table 13 contains a

18 The plant permit to construct contains details about the plant configuration and SCR, see BAAQMD (2010). Online date from Ventyx (2011).
19 See EPA (2011b).
20 See EPA (2011c).
21 See EPA (2011d).

summary of the resulting NO_X controls that we selected for each plant configuration, by location. All plants are assumed to have dry-low NO_X combustion, consistent with the 7FA turbine model. For all CONE Areas other than "Rest of RTO," the units are equipped with dual-fuel capability and are therefore also equipped with water injection.[22] Finally, we assume that all CC CT plants in ozone non-attainment areas will be equipped with an SCR, with the exception of the Dominion CT plant, assumed not to have an SCR. However, because of the current regulatory and technological uncertainty regarding the need for an SCR on CTs in each location, we also provide alternative CT CONE estimates in sensitivity cases that we recommend PJM and stakeholders use if these uncertainties are resolved in the future.

Table 13
NO_X Control Equipment for Gas CT and CC Plant

CONE Area	Gas CT			Gas CC		
	SCR (Y/N)	Dry Low NOx Burners (Y/N)	Water Injection (Y/N)	SCR (Y/N)	Dry Low NOx Burners (Y/N)	Water Injection (Y/N)
1 Eastern MAAC	Y	Y	Y	Y	Y	Y
2 Southwest MAAC	Y	Y	Y	Y	Y	Y
3 Rest of RTO	Y	Y	N	Y	Y	N
4 Western MAAC	Y	Y	Y	Y	Y	Y
5 Dominion	N	Y	Y	Y	Y	Y

H. DUAL-FUEL CAPABILITY

To determine whether each reference unit should be equipped with dual-fuel capability, we considered the prevalence of dual-fuel capability in existing and recently built units. We also analyzed the need for dual-fuel capability based on the frequency of gas curtailment events in each location.

Table 14 and Table 15 summarize dual-fuel or single-fuel capability for all CT and CC capacity for the states containing the selected location within each CONE Area. These tables show clear patterns in the Eastern MAAC, Rest of RTO, and Dominion CONE Areas. In Eastern MAAC, the majority of CTs and CCs have been equipped with dual-fuel capability. In the Rest of RTO area, almost no gas CTs and CCs have dual-fuel capability, except for one CT plant in Illinois. In the Dominion Area, dual-fuel capability is dominant for both gas CT and CC plants.

There was not a definitive pattern in the other two CONE Areas, due to the lack of recently constructed units in some cases and due to the mix of dual-fuel and non-dual-fuel plants in Western MAAC. To supplement our analysis in these areas, we examined the number of non-maintenance curtailments on the Transcontinental pipeline (which runs through all of the eastern CONE Areas) as well as the ANR pipeline (which runs through ComEd). Table 16 shows that curtailments on the Transco pipeline have been much more frequent than along the ANR pipeline. Based on this information and the predominance of dual-fuel capability in other eastern

[22] Our sensitivity case with dual-fuel capability in the Rest of RTO CONE Area is also equipped with water injection.

locations, we decided that these locations would be most appropriately fitted with dual-fuel capability.

Table 14
Single-Fuel and Dual-Fuel Gas CTs in Selected PJM States

CONE Area	State	Units Installed Since 2002			All Units Installed		
		Gas Only (MW)	Dual Fuel (MW)	Total (MW)	Gas Only (MW)	Dual Fuel (MW)	Total (MW)
1 Eastern MAAC	New Jersey	326	90	416	368	2,208	2,575
2 Southwest MAAC	Maryland	0	0	0	236	557	792
3 Rest of RTO	Illinois	2,192	456	2,648	5,736	456	6,192
4 Western MAAC	Pennsylvania	0	0	0	447	0	447
5 Dominion	Virginia	0	1,428	1,428	0	2,990	2,990

Sources and Notes:
Ventyx (2011).
Summary numbers include all PJM units within the selected state.

Table 15
Single-Fuel and Dual-Fuel Gas CCs in Selected PJM States

CONE Area	State	Units Installed Since 2002			All Units Installed		
		Gas Only (MW)	Dual Fuel (MW)	Total (MW)	Gas Only (MW)	Dual Fuel (MW)	Total (MW)
1 Eastern MAAC	New Jersey	766	1,780	2,546	820	2,735	3,555
2 Southwest MAAC	Maryland	0	0	0	0	0	0
3 Rest of RTO	Illinois	1,140	0	1,140	1,144	0	1,144
4 Western MAAC	Pennsylvania	1,920	1,130	3,050	2,589	1,130	3,719
5 Dominion	Virginia	0	1,494	1,494	0	2,801	2,801

Sources and Notes:
Ventyx (2011).
Summary numbers include all PJM units within the selected state.

Table 16
Non-Maintenance Curtailments Since 2010

	# of Curtailments
ANR Pipeline Co	3
Transcontinental Gas Pipe Line Corp	46

Sources and Notes:
Ventyx (2011).

To summarize, we determined that the reference units should have dual-fuel capability with the exception of the Rest of RTO CONE Area. However, for consistency and at the request of PJM, we also evaluated the cost of dual-fuel plants in the Rest of RTO area. We also considered whether units without dual-fuel capability would need to contract for firm gas delivery. We contacted several plant operators in the ComEd transmission zone and confirmed that they do not currently have firm gas delivery contracts. We therefore conclude that firm gas commitments need not be considered as part of our study.

I. GAS COMPRESSION

We determined that gas compression would generally not be needed for new gas plants located near and/or along the major gas pipelines selected in our study. Although gas pressures occasionally fall below the pressures the reference plants require, these instances are rare enough that gas compression capability would be generally unused. To support this conclusion we inquired with gas pipeline operators to confirm the average and realistic minimum expected gas pressures in each location. The New Jersey site has the lowest gas pressures of all CONE Areas; however, we confirmed with individual plant operators in New Jersey that no on-site gas compression was needed at their facilities. Further, these eastern plants' ability to meet capacity obligations is supported by having dual-fuel capability.

J. BLACK START CAPABILITY

We do not include black start capability in either the CC or the CT reference units because few recently built gas units have this capability. Table 17 shows the number of gas CT and CC units that have been built and are currently operating with or without black start capability since 2002 based on PJM data. We reviewed these data by CONE Area and found no locational differences.

Table 17
Black Start Capability in Gas Plants Built Since 2002

	Gas CT	Gas CC
Total Number of Plants Built	24	21
Total Number of Plants with Black Start	4	1

Sources and Notes:
PJM (2011a).

III. REFERENCE TECHNOLOGY PERFORMANCE AND SPECIFICATIONS

Table 18 shows the summary of plant characteristics selected in Section II as well as major plant performance characteristics as determined by CH2M HILL. As discussed in Section II.D, we identified the GE 7FA.05 turbine as the most appropriate technology for the reference gas CT and CC plants. This turbine is substantially larger than previous models, with the 7FA.05 model having an increased nominal capacity rating 36 MW relative to the 7FA.03, as well as having a substantially improved heatrate.[23] This increases output significantly for both the gas CT and CC plants relative to previous PJM CONE studies, due to the larger gas turbine in all configurations as well as an increased size for the heat recovery steam generator ("HRSG") and steam turbine on the CC. Table 19 contains a summary of emissions rates under each plant configuration.

[23] General Electric (2011a).

Table 18
Gas CT and CC Plant Characteristics and Performance

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

Sources and Notes:
Plant specifications are based on reference technology determination study as presented in Section II.
Plant technical performance data were determined by CH2M HILL (2011).

Table 19
Gas CT and CC Plant Emissions Rates

	NOx		VOC		CO	
	NG *(ppm)*	**Fuel Oil** *(ppm)*	**NG** *(ppm)*	**Fuel Oil** *(ppm)*	**NG** *(ppm)*	**Fuel Oil** *(ppm)*
Gas CT No SCR	9	42	7	7	9	20
Gas CT w/ SCR	2	5	5	5	5	11
Gas CC	2	5	5	5	5	11

Sources and Notes:
Plant emissions data were determined by CH2M HILL (2011).

IV. CAPITAL COST ESTIMATES

Costs for the gas CT and CC plants are broken into two categories: capital costs and fixed operation and maintenance ("FOM") costs. Capital costs are incurred when constructing the power plant, before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction ("EPC") company to complete construction and to ensure the plant operates properly. The costs of EPC contractor services, as well as the costs of major Owner-Furnished Equipment ("OFE"), were estimated by CH2M HILL as summarized in Section IV.A below for plant proper costs. There are additional owner's capital costs that a gas CT or CC developer would face, such as the purchasing of land, development costs, interconnection costs, start-up fuel, and owner's contingency which we estimate in Section IV.B.

A. Plant Proper Capital Costs

Plant proper costs include most of the costs required to engineer and construct a plant including the costs of major equipment and EPC services. CH2M HILL developed engineering cost estimates for the reference technology and sensitivity case estimates in our study as summarized here. Full documentation and supporting details regarding these estimates are included as Appendices A and B for the simple-cycle and combined-cycle technologies respectively.

1. Plant Developer and Contractor Arrangements

We asked CH2M HILL to assume that a plant owner will contract with an EPC services provider to engineer and construct the project. The EPC contractor would then be responsible for procuring all equipment and materials with the exception of major Owner-Furnished Equipment. The OFE consists of the plant gas turbines and SCR units for the simple-cycle plants, and the gas turbines, steam turbines, and HRSG units in the combined-cycle case. The OFE in our scenario is purchased by the owner and then assigned to the EPC contractor, meaning that, while the owner initially orders the equipment, the EPC contractor takes on responsibility for handling delivery and installation of the equipment.

We also asked CH2M HILL to assume that the EPC contractor will be taking on all contingency risk associated with cost overruns for all items within their scope. This associated contingency risk includes all contingency risk associated with the assigned OFE including delivery delays, but excludes any contingency risk associated with potential change orders to the EPC scope.

2. Owner-furnished Equipment and Sales Tax

The plant proper costs that will be paid directly by the owner include the costs of OFE and sales tax incurred in procuring the OFE, as well as the sales tax incurred by the EPC contractor and passed through to the owner. Table 20 summarizes these direct owner's costs for the simple-cycle plant, with OFE including two 7FA.05 gas turbines and a hot SCR. Table 21 summarizes these costs for the combined-cycle plant, with the OFE including two 7FA.05 gas turbines, a steam turbine, and two HRSG units. These owner costs are incurred over the capital drawdown schedule as summarized in Section IV.A.4. Additional supporting documentation for these costs is included in Appendix A for the simple-cycle and Appendix B for the combined-cycle configurations.

Table 20
CT Costs of Owner-Furnished Equipment and Sales Taxes

CONE Area	OFE				Sales Tax				Total	
	CT		SCR		OFE Scope		EPC Scope			
	($m)	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*
1 Eastern MAAC	$93.0	$238.7	$21.5	$55.2	$8.0	$20.6	$2.3	$6.0	$124.9	$320.5
2 Southwest MAAC	$93.0	$238.7	$21.5	$55.2	$6.9	$17.6	$2.0	$5.1	$123.4	$316.7
3 Rest of RTO	$90.0	$231.0	$21.5	$55.2	$7.8	$20.0	$2.0	$5.2	$121.3	$311.4
4 Western MAAC	$93.0	$238.7	$21.5	$55.2	$6.9	$17.6	$2.0	$5.2	$123.4	$316.7
5 Dominion	$93.0	$237.2	$0.0	$0.0	$4.7	$11.9	$1.8	$4.6	$99.5	$253.7

Sources and Notes:
Owner-furnished equipment and sales tax data provided by CH2M HILL (2011).

Table 21
CC Costs of Owner-Furnished Equipment and Sales Taxes

CONE Area	OFE						Sales Tax				Total	
	CT		HRSG		ST		OFE Scope		EPC Scope			
	($m)	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*	*($m)*	*($/kW)*
1 Eastern MAAC	$93.0	$141.8	$41.0	$62.5	$42.0	$64.1	$12.3	$18.8	$6.5	$9.9	$194.8	$297.1
2 Southwest MAAC	$93.0	$141.8	$41.0	$62.5	$42.0	$64.1	$10.6	$16.1	$5.5	$8.4	$192.1	$292.9
3 Rest of RTO	$90.0	$137.3	$41.0	$62.5	$42.0	$64.1	$12.1	$18.5	$6.1	$9.4	$191.3	$291.7
4 Western MAAC	$93.0	$141.8	$41.0	$62.5	$42.0	$64.1	$10.6	$16.1	$5.5	$8.5	$192.1	$293.0
5 Dominion	$93.0	$141.8	$41.0	$62.5	$42.0	$64.1	$8.8	$13.4	$4.6	$7.0	$189.4	$288.9

Sources and Notes:
Owner-furnished equipment and sales tax data provided by CH2M HILL (2011).

3. Engineering Procurement and Construction Costs

All other plant proper costs are paid to the EPC contractor as summarized in Table 22 and Table 23. These costs include all EPC costs required to engineer and construct the plant after considering specific locational and time-dependent escalation rates for materials, equipment, and labor. Direct project costs include, but are not limited to, materials, instrumentation, site work, craft labor, freight, and balance of plant ("BOP") mechanical and electrical equipment. Indirect costs include taxes, builder's all risk insurance, and performance and payment bonds. Management costs include project management, engineering, procurement, site management, and startup. Contingency costs are incorporated for all potential cost over-runs within EPC scope and a project profit margin is included.

These EPC costs are incurred over the capital drawdown schedule as summarized in Section IV.A.4. Additional supporting documentation for these costs is included in Appendix A for the simple-cycle and Appendix B for the combined-cycle configurations.

Table 22
EPC Costs for Gas CT Plants

CONE Area		EPC Costs ($m)	EPC Costs ($/kW)
1	Eastern MAAC	$130.6	$335.1
2	Southwest MAAC	$105.0	$269.5
3	Rest of RTO	$113.6	$291.5
4	Western MAAC	$123.0	$315.8
5	Dominion	$104.0	$265.3

Sources and Notes:
EPC Costs provided by CH2M HILL (2011).

Table 23
EPC Costs for Gas CC Plants

CONE Area		EPC Costs ($m)	EPC Costs ($/kW)
1	Eastern MAAC	$356.2	$543.3
2	Southwest MAAC	$274.6	$418.8
3	Rest of RTO	$334.9	$510.8
4	Western MAAC	$333.4	$508.6
5	Dominion	$274.4	$418.5

Sources and Notes:
EPC Costs provided by CH2M HILL (2011).

4. Capital Drawdown Schedules

CH2M HILL has developed monthly capital drawdown schedules over the project development period for each plant configuration. Separate monthly drawdown schedules have been developed for the direct owner's plant proper costs identified in Section IV.A.2, as well as for the EPC costs identified in Section IV.A.3. These drawdown schedules differ slightly for each plant, but representative drawdown schedules are included for one simple-cycle plant in Appendix A.5, consistent with the project schedule in Appendix A.4, as well as for one combined-cycle plant in Appendix B.5 consistent with the project schedule in Appendix B.4.

B. OWNER'S CAPITAL COSTS

Outside of the plant proper owner and EPC costs, there are additional costs an owner must incur in the development and construction of a generating plant. We estimate these costs, which include land, emissions reductions credits, gas interconnection, electric interconnection, start-up fuel during testing, and owner's contingency. We developed these cost estimates based on publicly-available sources, except for project development and owner's contingency, for which estimates are based on industry experience and conversations with a number of project developers and plant operators.

1. Land

We estimated the cost of land by reviewing historical transaction prices and current asking prices for vacant industrial land for sale in each selected county. We narrowed the recent transactions and current land offers by looking only at land greater than 20 acres, and considering only sites listed as vacant or classified as "unimproved land." We estimated land costs using a weighted average of historical transaction prices when available, supplemented with current asking prices. Table 24 shows the range and number of observations for current asking prices as well as recent transactions on industrial land.

Table 24
Current and Historical Land Costs

CONE Area	County	Current Asking Prices		Recent Transactions	
		Range	Observations	Range	Observations
		($000/acre)	*(count)*	*($000/acre)*	*(count)*
1 Eastern MAAC	Middlesex, NJ	$70-$236	5	$228-$306	2
2 Southwest MAAC	Charles County, MD	$78-$217	6	$97-$217	4
3 Rest of RTO	Will, IL	$42-$217	15	$83-$189	4
4 Western MAAC	Northampton, PA	$13-$209	8	$136	1
5 Dominion	Fauquier, VA	$42-$335	2	$11-$34	3

Sources and Notes:
Current Asking Prices from LoopNet (2011).
New Jersey Assessment Records (2011).
Maryland Assessment Records (2011).
Illinois Assessment Records (2011).
Pennsylvania Assessment Records (2011).
Virginia Assessment Records (2011).

Table 25 shows the resulting land prices we used for each CONE Area (calculated by taking a weighted average of the historical transactions and current offerings). We also include the acreage needed, based on recommendations from CH2M HILL, and report the final estimated cost for the land for each location.

Table 25
Gas CT and CC Land Costs

CONE Area	County	Land Price	Acreage		Cost	
			Gas CT	Gas CC	Gas CT	Gas CC
		($/acre)	*(acres)*	*(acres)*	*($m)*	*($m)*
		[1]	[2]	[3]	[4]	[5]
1 Eastern MAAC	Middlesex, NJ	$129,000	30	40	$3.87	$5.16
2 Southwest MAAC	Charles County, MD	$120,000	30	40	$3.60	$4.80
3 Rest of RTO	Will, IL	$80,000	30	40	$2.40	$3.20
4 Western MAAC	Northampton, PA	$90,000	30	40	$2.70	$3.60
5 Dominion	Fauquier, VA	$118,000	30	40	$3.54	$4.72

2. Emissions Reductions Credits

As part of its NSR, a plant may be required to procure emissions reductions credits (ERCs) in areas that are in Maintenance or Nonattainment of the EPA's National Ambient Air Quality Standards (NAAQS). ERCs represent permanent reductions in air quality pollutants that must be purchased to offset the emissions of new major sources. A new plant must obtain ERCs from nearby existing facilities that have created ERCs by permanently reducing their emissions output through retirement or other means.[24] We estimate ERC costs for VOCs and NO_X, which are precursors to ozone and for which both the CC and CT plants will be considered major sources.

To estimate the number of ERCs needed, we started with two recently permitted plants, the Bayonne Energy Center gas CT and the York Energy Center gas CC facilities. Both air permits specify a potential to emit (PTE), or the maximum potential emissions limit for the year.[25] We then developed an estimate of PTE for each reference plant by scaling based on each plant's heatrate, emissions rate, and total MW rating as summarized in Table 26.

Table 26
Total Potential to Emit

			Emission Rates		Potential to Emit	
	Capacity *(MW)*	**Heat Rate** *(btu/kWh)*	**NO_x** *(ppm)*	**VOC** *(ppm)*	**NO_x** *(tpy)*	**VOC** *(tpy)*
Recently Permitted Plants						
Bayonne (CT)	512	9,519	2.5	2.5	109.5	36.8
York Energy Center (CC)	1,100	7,727	2.0	2.0	460.2	46.2
Reference Technology						
Gas CT No SCR	392	10,036	9.0	7.0	318.2	83.2
Gas CT w/ SCR	390	10,094	2.0	5.0	70.8	59.5
Gas CC	656	6,722	2.0	5.0	238.8	59.9

Sources and Notes:
See Bayonne Permits Obtained (2011), pg. 151 for capacity, pg. 158 for emission rates, and pg. 76 for PTE
See York Energy Center Permits Obtained (2005) for capacity, emissions rates, and potential to emit
See Ventyx (2011) for heat rate information
See CH2M HILL Engineers, Inc. (2011) for reference technology specifications.

We used locational cost estimates for ERCs provided by CH2M HILL to determine the total compliance costs as shown in Table 27 and Table 28. In each case the total ERCs that must be procured is also multiplied by a location-specific offset ratio, reflecting the requirement to procure offsets in excess of PTE at a rate that depends on the severity of ozone Nonattainment as reported previously in Table 12. Because Dominion is in Attainment, we do not estimate ERC costs for that location.

[24] See EPA (2011e)
[25] See Bayonne Permits Obtained (2011) and York Energy Center Permits Obtained (2005).

Table 27
Gas CT Emission Reduction Credits

CONE Area	Emissions Offsets		Emission Offset Cost and Ratio				ERC Costs		
	NOx	VOC	NOx	VOC	NOx	VOC	NOx	VOC	Total
	(tpy)	*(tpy)*	*($/tpy)*	*($/tpy)*	*(ratio)*	*(ratio)*	*($m)*	*($m)*	*($m)*
1 Eastern MAAC	71	59	$4,000	$4,000	1.30	1.30	$0.37	$0.31	$0.68
2 Southwest MAAC	71	59	$3,000	$5,000	1.30	1.30	$0.28	$0.39	$0.66
3 Rest of RTO	71	59	$5,000	$4,000	1.15	1.15	$0.41	$0.27	$0.68
4 Western MAAC	71	59	$4,000	$4,000	1.15	1.15	$0.33	$0.27	$0.60
5 Dominion	--	--	--	--	--	--	--	--	--

Sources and Notes:
Emissions offsets from Table 25.
Emission offset costs from CH2M HILL Engineers, Inc. (2011).
Emission offset ratios from Evolution Markets (2011).

Table 28
Gas CC Emission Reduction Credits

CONE Area	Emissions Offsets		Emission Offset Cost				ERC Costs		
	NOx	VOC	NOx	VOC	NOx	VOC	NOx	VOC	Total
	(tpy)	*(tpy)*	*($/tpy)*	*($/tpy)*	*(ratio)*	*(ratio)*	*($)*	*($)*	*($)*
1 Eastern MAAC	239	60	$4,000	$4,000	1.30	1.30	$1.24	$0.31	$1.55
2 Southwest MAAC	239	60	$3,000	$5,000	1.30	1.30	$0.93	$0.39	$1.32
3 Rest of RTO	239	60	$5,000	$4,000	1.15	1.15	$1.37	$0.28	$1.65
4 Western MAAC	239	60	$4,000	$4,000	1.15	1.15	$1.10	$0.28	$1.37
5 Dominion	--	--	--	--	--	--	--	--	--

Sources and Notes:
Emissions offsets from Table 25.
Emission offset costs from CH2M HILL Engineers, Inc. (2011).
Emission offset ratios from Evolution Markets (2011).

3. Gas Interconnection

To estimate gas interconnection costs, we used historical gas lateral interconnection costs filed with the Federal Energy Regulatory Commission ("FERC"). Each gas plant must build a lateral pipeline from a major natural gas pipeline in order to operate. Total pipeline costs depend on several factors, including pipeline width, pipeline length, terrain, right-of-way costs, and whether a project has a metering station, which measures quality and amount of natural gas being transferred in a pipeline. Table 29 shows historical pipeline costs for several projects with publicly-reported costs.

Table 29
Historical Gas Lateral Project Costs Filed with FERC

Expansion		State	Pipeline Width	Pipeline Length	Pipeline Cost	Meter Station	Station Cost
			(inches)	*(miles)*	*($m/mile)*	*(Y/N)*	*(m$)*
Delta Lateral Project	[1]	DE	16	3.42	$2.77	Y	$3.33
MarkWest	[2]	NM	16	3.16	$1.10	N	n/a
Texas Eastern Transmission	[3]	LA	20	3.79	$3.76	Y	$3.16
Gulfstream	[4]	FL	20	17.74	$3.44	Y	$3.72
Bayonne Delivery Lateral Project	[5]	NJ	20	6.24	$2.21	Y	$3.86
Columbia Gas	[6]	NJ	24	23.80	$1.63	Y	$3.09
Duke Energy Indiana	[7]	IN	20	19.50	$1.92	Y	$3.75
Average					**$2.40**		**$3.48**

Sources and Notes:
[1] Delta Lateral Project (2009).
[2] MarkWest (2007).
[3] Texas Eastern Transmission Co. (2007).
[4] Gulfstream (2006).
[5] Bayonne Delivery Lateral Project (2009).
[6] Columbia Gas (2001).
[7] Duke Energy Indiana, Inc. (2010).

Pipeline lengths range from 3 to 23 miles. For the gas CT and CC plants in our study, we selected siting locations in the same county as a major gas pipeline, with a reasonable availability of vacant industrial land. For this reason, we assume that each plant will interconnect with a pipeline with a 5-mile gas lateral, a reasonable assumption based on historical pipeline lengths. In addition, each plant will be equipped with a metering station.[26] Total gas interconnection costs vary widely from location to location, but we estimate a cost consistent with the average observed. We estimate the total gas interconnection cost for each CONE area is $16 million based on $2.5 million per mile for 5 miles plus $3.5 million for the metering station.

4. Electric Interconnection

We estimated electric interconnection costs based on historical electric interconnection cost data provided by PJM.[27] Electric interconnection costs consist of two categories of costs: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network. Network upgrade costs do not always occur, but are incurred when improvements, such as replacing the transformer, are required.

To determine the most appropriate basis for determining expected interconnection costs, we reviewed interconnection costs for plants recently built and summarized them by voltage, plant size, and location. The total range of interconnection costs is quite large, depending on both voltage and plant size. Interconnections below 138kV vary substantially as a function of voltage and can be quite low, while interconnection costs above that threshold did not appear to vary substantially by voltage. For projects above 138kV, plant size is another factor affecting

[26] Note that while meter stations are not included in all projects in Table 29, this means only that the meter station cost was not included as part of the public filing, not that the project was without a meter station.
[27] PJM Interconnection, L.L.C. (2011a).

interconnection costs, as summarized in Table 31. We did not observe any systematically different costs by location. The wide range of costs, particularly network upgrade costs, over a relatively small number of observations for large plants, means that the upgrade costs for any individual project may vary substantially. To estimate costs for our reference plants, we examined the costs for similarly-sized plants.

For the CT, we reviewed interconnection costs for 300-500 MW plants. The average direct interconnect cost was $3.1 million and the average network upgrade cost was $7.7 million, for a total of $10.8 million. For the CC, we considered 500-750 MW plants The average direct interconnect cost is $7.7 million and the average network upgrade cost is $7.9 million. Based on these numbers, we estimate the total interconnection costs at approximately $11.0 million for the CT and $15.5 million for the CC.

Table 30
Historical Electric Interconnection Costs in PJM

		Direct Interconnection Costs		Network Upgrade Costs		Total Costs	
Plant Size	**Observations** *(count)*	**Avg.** *($m)*	**Median** *($m)*	**Avg.** *($m)*	**Median** *($m)*	**Avg.** *($m)*	**Median** *($m)*
100-300 MW	5	$1.1	$0.2	$4.4	$0.1	$5.5	$0.3
300-500 MW	4	$3.1	$3.2	$7.7	$6.7	$10.8	$9.8
500-750 MW	9	$7.7	$4.0	$7.9	$2.5	$15.6	$6.5

Sources and Notes:
Source is PJM (2011a).
Excludes plants that are interconnected at 138kV or lower.

5. Net Start-Up Fuel Costs during Testing

Before commencing full commercial operations, new generation plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas, as well as fuel oil if it has dual-fuel capability. We received fuel consumption and energy production data from CH2M HILL for each plant type based on data from recently built projects.[28] During testing, a plant will pay for the natural gas and fuel oil consumption, and will receive revenues for its energy production.

We estimated the cost of natural gas using Henry Hub futures through 2015 and adding a basis differential to each delivery point. We used the Chicago Citygate basis differential for the Rest of RTO CONE Area, and our estimate of the Transco Zone 6 Non-New York (Z6 NNY) basis for all other CONE areas.[29] We averaged the delivered price over the months of testing to obtain

28 Reported in Appendices A.1 and B.1 for the simple cycle and combined cycle plants respectively.

29 Because Z6 NNY basis future is an illiquid product there are no futures data available there. Instead we used the Zone 6 New York (Z6 NY) basis after adjusting for the historical relationship between the two. Historically, the Z6 NNY and Z6 NY prices are nearly identical except for three winter months when the Z6 NY prices spikes much higher than (but with a strong correlation to) the Z6 NNY price. Because neither the Z6 NY and Chicago Citygate basis futures are available as far forward as 2015, we increased the monthly-varying basis futures at the rate of inflation for subsequent years. Henry hub futures and basis differentials were downloaded from Bloomberg (2011).

a natural gas price estimate. We estimated the cost of fuel oil using distillate futures through 2012, extended to 2015 using historical relationship between crude oil and distillate prices.[30]

We estimated the future energy price based on PJM Eastern Hub for Eastern MAAC, Northern Illinois Hub for the Rest of RTO, and PJM Western Hub for all other CONE Areas.[31] We calculated a 2012 market heat rate based on electricity and gas futures in each location, and assuming this market heat rate would remain constant to 2015. We averaged the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing. Table 31 summarizes these gas, oil, and energy price estimates as well as our total resulting net startup cost estimates. Net costs are highest in the Rest of RTO Area where energy prices are lowest, and are lower for CC plants, which have a lower heatrate and whose costs will be lower relative to their revenues. In Eastern MAAC our net startup fuel cost is actually negative due to our higher energy price estimate in that location.

Table 31
Startup Production and Fuel Consumption During Testing

	Energy Production			Fuel Consumption						
	Energy Produced *(MWh)*	**Energy Price** *($/MWh)*	**Energy Sales** *($m)*	**Natural Gas** *(MMBtu)*	**Natural Gas Price** *($/MMBtu)*	**NG Cost** *($m)*	**Fuel Oil** *(MMBtu)*	**Fuel Oil Price** *(MMBtu)*	**Fuel Oil Cost** *($m)*	**Total Cost** *($m)*
Gas CT										
1 Eastern MAAC	215,000	62.7	13.5	2,000,000	7.02	14.0	75,060	21.9	1.6	2.21
2 Southwest MAAC	215,000	54.8	11.8	2,000,000	7.02	14.0	75,060	21.9	1.6	3.90
3 Rest of RTO	215,000	41.6	8.9	2,000,000	5.67	11.3	75,060	21.9	1.6	4.05
4 Western MAAC	215,000	54.8	11.8	2,000,000	7.02	14.0	75,060	21.9	1.6	3.90
5 Dominion	215,000	54.8	11.8	2,000,000	7.02	14.0	75,060	21.9	1.6	3.90
Gas CC										
1 Eastern MAAC	546,788	62.7	34.3	4,138,657	7.24	30.0	75,060	22.1	1.7	-2.65
2 Southwest MAAC	546,788	54.8	30.0	4,138,657	7.24	30.0	75,060	22.1	1.7	1.66
3 Rest of RTO	546,788	41.6	22.8	4,138,657	5.71	23.7	75,060	22.1	1.7	2.56
4 Western MAAC	546,788	54.8	30.0	4,138,657	7.24	30.0	75,060	22.1	1.7	1.66
5 Dominion	546,788	54.8	30.0	4,138,657	7.24	30.0	75,060	22.1	1.7	1.66

Sources and Notes:
Energy production and fuel consumption from CH2M HILL Engineers, Inc. (2011).
Energy and fuel prices from Bloomberg (2011).

6. O&M Mobilization and Startup

Concurrent with their estimates of O&M and service agreement costs presented in Sections 30V.CV.EV.E and X, Wood Group has provided estimates of pre-operation mobilization costs. These costs summarized in Table 32 would be incurred during construction in the last year prior to the commercial online date. Additional supporting details for these estimates are included in Appendix C.

[30] Number 2. distillate and WTI Cushing crude oil futures from Bloomberg (2011).
[31] Mapping is based on the portion of price nodes in each zone that are combined for the aggregate hub node price.

Table 32
Pre-Operation Mobilization Costs

CONE Area	Gas CT *($m)*	Gas CC *($m)*
1 Eastern MAAC	$1.2	$2.9
2 Southwest MAAC	$1.1	$2.7
3 Rest of RTO	$1.1	$2.8
4 Western MAAC	$1.1	$2.6
5 Dominion	$1.0	$2.6

Sources and Notes:
For additional details see Wood Group report in Appendix C.

7. Project Development, Financing Fees, and Owner's Contingency

For several categories of owner's costs, there are no readily available public sources documenting them. We estimated these costs based on industry experience and discussions with a number of project developers and plant operators.

Project development costs are the owner's costs for all development activities from the initial feasibility studies through project startup, exclusive of plant proper and other owner's costs that we estimated separately. These costs include market studies, interconnection studies, staff time for project development, permitting fees, legal fees, water and sewer interconnection, and technical professionals hired throughout development and construction. Owner's costs also include financing fees to pay lenders for securing the project debt, financial advisor fees, and legal fees for contract support, including gas procurement contracts, construction contracts, lease agreements, and O&M contracts. We estimate these fees at $6 million for the simple-cycle and $8 million for the combined-cycle plants. We estimate financing fees at 200 basis points applied to the 50% portion of the project financed with debt as discussed in detail in Section VI.

Owner's contingency reflects the expected value of unforeseen cost categories that may fall outside of the original scope of the project, additional materials needed, unforeseen costs incurred for permits or land, or price increases on materials not anticipated by the owner. Our estimates are consistent with our assumed arrangement in which the EPC contractor will take on all contingency risk associated with cost items in their scope, but will not take on any risks associated with change orders. Further, we considered the actual expected realized contingency costs, and excluded any reserve funds that may often be set aside in case of contingency but that would not be expected to be spent on average. Finally, we excluded contingencies associated with gas and electric interconnections since our estimates in those categories already reflect an expected value based on the average of actual projects. The owner's contingency estimate is 3% of total project oversight costs before considering contingency or interest during construction ("IDC").

V. FIXED AND VARIABLE OPERATION AND MAINTENANCE COSTS

Once the plant enters commercial operation, the plant owners incur fixed costs each year, including property taxes, plant insurance, facility fees for operating labor and minor maintenance, and asset management costs. We subcontracted with the O&M services provider Wood Group Power Operations, Inc. to estimate facility operation and maintenance fees as part of our Gross CONE calculation. Wood Group also provided estimate for variable O&M costs and major maintenance and long-term service agreement ("LTSA") costs for use in PJM's dispatch modeling of E&AS offsets.

A. PROPERTY TAX

We calculated property tax rates for each location using state and county property records to calculate the implied tax rate based on 2010 taxes paid by the current plant owners in each CONE Area. For each location, we determined the relevant tax rates, which in many cases apply only to the assessed value of land, but in other cases also apply to the value of the plant. Table 33 contains a summary of the plant tax rates and total annual taxes in each county where we estimated the first year of operation (increasing each year by the 2.5% inflation rate that we estimated in Section VI.A).

For Eastern MAAC we considered property tax rates paid by 3 different power plant owners in Middlesex, NJ.[32] Each owner paid 4.25% property taxes on the land only and had no additional taxes for the plant on the land. In Southwest MAAC, power plant owners paid 1.14% tax on land and $831/MW tax on the power plant.[33] In the Rest of RTO CONE Area represented by Will County, IL, property taxes are 1.72% of land market value[34] (5.15% tax rate on one-third land market value).[35] In Western MAAC, the power plant owner paid taxes at a rate of 3.02% on the value of the land plus $135/MW on the power plant.[36] In Dominion, we found property taxes did not need to be paid by power plants in Fauquier County, and the Commissioner of the Revenue Office confirmed that power plants are exempt from property tax.

32 Used property tax information from AES Red Oak, LLC., North Jersey Energy Associates, and Reliant Energy NJ Holdings. See New Jersey Assessment Records (2011).

33 Used property tax information from Mirant Mid-Atlantic LLC. See Maryland Assessment Records (2011).

34 Illinois Department of Revenue (2011), p. 11.

35 Used property tax information from Midwest Generation LLC. See Illinois Assessment Records (2011).

36 Used property tax information from Conectiv Bethlehem LLC. See Pennsylvania Assessment Records (2011).

Table 33
Property Taxes for Gas CT and CC Plants

CONE Area	County	Property Tax Rate		Property Tax	
		Land	Plant	Gas CT	Gas CC
		(%)	*($/MW-yr)*	*($/yr)*	*($/yr)*
1 Eastern MAAC	Middlesex, NJ	4.25%	$0	$164,475	$219,300
2 Southwest MAAC	Charles County, MD	1.14%	$831	$390,060	$637,251
3 Rest of RTO	Will, IL	1.72%	$0	$41,163	$54,884
4 Western MAAC	Northampton, PA	3.02%	$135	$138,240	$203,355
5 Dominion	Fauquier, VA	0.00%	$0	$0	$0

Sources and Notes:
New Jersey Assessment Records (2011).
Maryland Assessment Records (2011).
Illinois Assessment Records (2011).
Pennsylvania Assessment Records (2011).
Virginia Assessment Records (2011).

B. Insurance

We estimated insurance costs by contacting insurance companies with experience insuring gas CT and CC plants. Insurance coverage includes general liability, property, boiler and machinery, and business interruption. We estimated the annual premiums for the CT and CC plants at $1.75 million and $3.75 million respectively for the first online year, increasing at the 2.5% inflation rate that we estimated in Section VI.A.

C. Annual Fixed Fees for Plant Operation and Maintenance

We subcontracted with Wood Group to estimate annual fixed O&M costs. Table 34 and Table 35 show the first year annual fixed O&M expenses for the CT and CC reference plant in each location, with costs increasing with inflation over time. The largest component of the fixed operating expenses is the staff labor costs, accounting for approximately half of the total fixed O&M costs depending on plant type and location. The remaining annual O&M services costs are comprised of consumables, office administration, maintenance and minor repairs, and corporate and administrative charges. Additional supporting details for the Wood Group estimates are contained in Appendix C.

Table 34
Gas CT First Year Annual Fixed O&M Expenses

	CONE Area				
	1	**2**	**3**	**4**	**5**
	EMAAC	**SWMAAC**	**RTO**	**WMAAC**	**DOM**
	($m)	*($m)*	*($m)*	*($m)*	*($m)*
Facility Staff Labor Costs	$1.47	$1.30	$1.38	$1.26	$1.25
Consumables	$0.16	$0.16	$0.16	$0.16	$0.16
Office Administration	$0.16	$0.16	$0.16	$0.16	$0.16
Maintenance & Minor Repairs	$0.51	$0.51	$0.51	$0.51	$0.51
Corporate & Administrative Charges	$0.41	$0.41	$0.41	$0.41	$0.41
Total	**$2.72**	**$2.54**	**$2.62**	**$2.50**	**$2.50**

Sources and Notes:
For additional details see Wood Group report in Appendix C.

Table 35
Gas CC First Year Annual Fixed O&M Expenses

	CONE Area				
	1	**2**	**3**	**4**	**5**
	EMAAC	**SWMAAC**	**RTO**	**WMAAC**	**DOM**
	($m)	*($m)*	*($m)*	*($m)*	*($m)*
Facility Staff Labor Costs	$3.88	$3.45	$3.63	$3.34	$3.31
Consumables	$0.30	$0.30	$0.30	$0.30	$0.30
Office Administration	$0.21	$0.21	$0.21	$0.21	$0.21
Maintenance & Minor Repairs	$0.92	$0.92	$0.92	$0.92	$0.92
Corporate & Administrative Charges	$0.43	$0.43	$0.43	$0.43	$0.43
Total	**$5.74**	**$5.31**	**$5.49**	**$5.20**	**$5.17**

Sources and Notes:
For additional details see Wood Group report in Appendix C.

D. Asset Management Costs

Asset management costs are costs associated with ongoing compliance, permitting, legal, contract management, fuel management, accounting, energy sales management, ISO interface, and administrative overhead. We estimated asset management costs at $1.5 million annually for both the CT and CC plants based on estimates provided to us by several asset owners.

E. Variable Operation and Maintenance Costs

Variable operation and maintenance ("VOM") costs are not part of gross CONE but are needed for estimating administrative E&AS offsets. Wood Group has estimated two components of these VOM costs consistent with their other O&M estimates: (1) the relatively small variable component of the facilities O&M costs, primarily consisting of consumables, and (2) the larger costs associated with major maintenance overhauls though an LTSA. Table 36 contains a summary of these variable costs by CONE Area.

As explained in more detail in Appendix C, the LTSA contract structures vary, but we asked Wood Group to assume a contract structure that would be appropriate to use over a range of operating profiles. The timing of LTSA payments (and major maintenance events) depends on plant operations as measured typically through factored fired starts ("FFS") or factored fired hours ("FFH").[37] For simple-cycle plants, LTSA costs are typically determined on a starts basis as a function of FFS. For combined-cycle plants, LTSA costs may be either starts-based or hours-based depending on how much the plant is cycling. Based on guidance from Wood Group about one type of typical contract structure, we assume that if the plant cycles frequently with the FFH:FFS ratio ≤ 27, then all LTSA costs would be assessed on an starts basis. If the plant cycle less frequently with long duty cycles and an FFH:FFS ratio > 27 then the LTSA would be hours-based.

Table 36
Variable O&M and LTSA Costs

CONE Area	Gas CT		Gas CC		
	VOM *($/MWh)*	**LTSA** *($/FFS)*	**VOM** *($/MWh)*	**LTSA** *($/FFS)*	**LTSA** *($/FFH)*
1 Eastern MAAC	$0.91	$19,846	$0.85	$10,370	$311
2 Southwest MAAC	$0.91	$17,501	$0.85	$9,144	$274
3 Rest of RTO	$0.91	$18,565	$0.85	$9,700	$291
4 Western MAAC	$0.91	$16,968	$0.85	$8,866	$266
5 Dominion	$0.87	$16,887	$0.85	$8,823	$265

Sources and Notes:
For additional details see Wood Group report in Appendix C.
All LTSA costs would be hours-based if FFH:FFS > 30, or all starts-based otherwise.

VI. FINANCIAL ASSUMPTIONS

A. INFLATION

Inflation rates affect our net CONE estimates by forming the basis for projected increases in several FOM costs over time. We also use the inflation rate as cost escalation rate in our level-real CONE estimate as discussed in Section VII.C. We estimated future inflation rates based on bond market data and consensus U.S. economic projections. Table 37 shows that the implied inflation rate from Treasuries is 2.3% over 5 years, 2.6% over 10 years, and 2.8% over 20 years as of late April 2011. Figure 3 shows the historical nominal and inflation protected yields, as well as the implied inflation since 2008. Since 2011, implied inflation averaged approximately 2.5%.

These implied rates are consistent with consensus projections. The monthly Blue Chip Economic Indicators report compiles analyst forecasts from various financial institutions and has

[37] FFS and FFH account for the number of starts or the number of fire-hours experienced, but also consider other factors that will contribute to requiring maintenance to be scheduled earlier. Two examples of these factors include whether the starts were on gas or oil and whether the unit has tripped, although a full account of these factors can be obtained from the turbine manufacturer, see Appendix C.

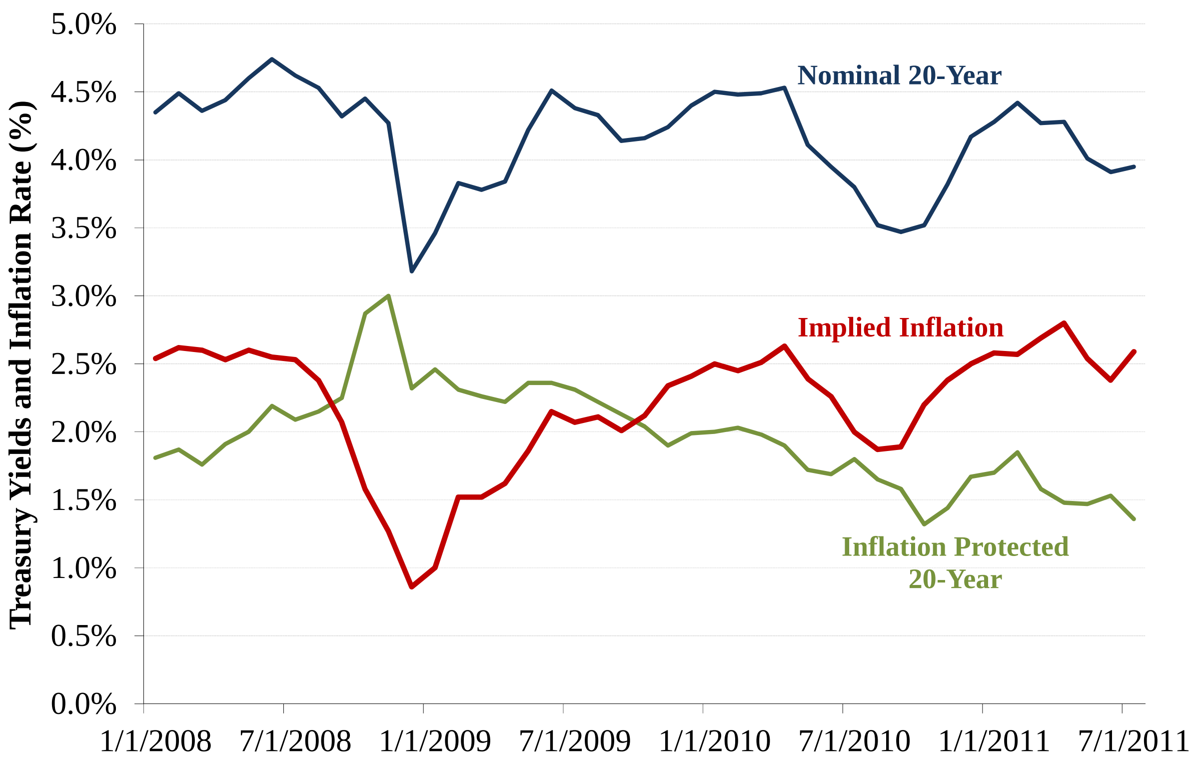
consensus forecasts for various economic variables. The consensus ten-year average consumer price index ("CPI") forecast through 2022 is 2.4%.[38] Based on these two sources, we chose an estimated average long-term inflation rate of 2.5%.

Table 37
Implied Inflation from Treasury Yields

	5-year (%)	10-year (%)	20-year (%)
Nominal Yield	2.2%	3.5%	4.3%
Inflation Protected Yield	-0.1%	0.9%	1.5%
Implied Inflation	2.3%	2.6%	2.8%

Sources and Notes:
Yields as of April 25, 2011.
Bloomberg (2011).

Figure 3
Implied Inflation Since 2008



Sources and Notes:
Bloomberg (2011).

[38] Blue Chip Economic Indicators (2011), p. 15.

B. Income Tax and Depreciation Schedule

All corporations with an income above $18.3 million have a marginal federal tax rate of 35%.[39] We estimate that the gas CT or CC plant will need to earn at least approximately twice that amount in net annual income to be economically viable as determined in Section VII.C, placing it in the highest corporate tax bracket. In addition, the plants will be subject to a state-specific income tax rate as summarized in Table 38.

Table 38
State Corporate Income Tax Rates

CONE Area		State	Tax Rate *(%)*
1	Eastern MAAC	New Jersey	9%
2	Southwest MAAC	Maryland	8.25%
3	Rest of RTO	Illinois	9.5%
4	Western MAAC	Pennsylvania	9.99%
5	Dominion	Virginia	6%

Sources and Notes:
Tax Foundation (2011)
NJ corporate tax rate is for income greater than $100,000. All other states are for income greater than $0.

The Federal tax code allows generating companies to use a Modified Accelerated Cost Recovery System ("MACRS") of 15 years for a Gas CT plant and 20 years for a Gas CC plant.[40] Table 39 shows this depreciation schedule as a function of the operating year.

39 IRS (2010a).
40 Asset classes 49.13 and 49.15, see IRS (2010b).

Table 39
MACRS Depreciation Schedule

Year	Gas CT *(%)*	Gas CC *(%)*
1	8.75%	6.56%
2	9.13%	7.00%
3	8.21%	6.48%
4	7.39%	6.00%
5	6.65%	5.55%
6	5.99%	5.13%
7	5.90%	4.75%
8	5.91%	4.46%
9	5.90%	4.46%
10	5.91%	4.46%
11	5.90%	4.46%
12	5.91%	4.46%
13	5.90%	4.46%
14	5.91%	4.46%
15	5.90%	4.46%
16	0.74%	4.46%
17		4.46%
18		4.46%
19		4.46%
20		4.46%
21		0.57%
Sum	**100.0%**	**100.0%**

Sources and Notes:
IRS (2010b), Table A-2.

C. COST OF CAPITAL

The financing assumptions and cost of capital we used in developing CONE are consistent with a merchant generation project that is balance-sheet financed by a larger corporate entity. To inform our cost of capital estimate, we calculated the after-tax weighted-average cost of capital ("ATWACC") for a portfolio of publicly-traded merchant generation companies. We also considered ATWAAC estimates from equity analysts and fairness opinions rendered in recent merger and acquisition transactions as summarized in Section VI.C.2. After considering each of these pieces of information, we developed a recommended estimate of the ATWACC as reported in Section VI.C.2.

1. Estimated Cost of Capital for a Portfolio of Merchant Generation Companies

In calculating a cost of capital estimate, we examined a value-weighted portfolio and the five publicly-traded merchant generation companies: NRG, Calpine, Dynegy, GenOn Energy (formerly known as RRI Energy), and GenOn Energy Holdings (formerly known as Mirant).[41] Table 40 shows the market capitalization of these companies. For each of these companies, we estimated the return on equity, cost of debt, debt-to-equity ratio, and ATWAAC.

Table 40
Market Capitalization of Merchant Generation Companies

	Market Capitalization *($m)*
NRG Energy, Inc.	$5,163
GenOn Energy Inc (fka RRI Energy)	$1,467
Calpine Corp.	$6,861
GenOn Energy Holdings Inc (fka Mirant)	$1,271
Dynegy, Inc.	$696

Source: Bloomberg (2011).

a. Return on Equity

We estimate the return on equity (ROE), the return that stockholders require to invest in a company, using the Capital Asset Pricing Model ("CAPM") for each merchant generation company as shown in Table 41. The ROE for each company is the risk free rate for U.S. treasuries plus a risk premium, defined as a company's beta multiplied by the market premium.[42]

We calculate the risk free rate of 4.3% using a 15-day average of 20-year U.S. treasuries as of April 2011.[43] We estimate a market risk premium of 6.5% based on an average of long-term equity risk premia of 6.7% and 6.3% from Ibbotson and Credit Suisse.[44] The company beta describes a company's correlation with the market; we calculate each company's beta using the S&P 500 over the last five years.[45]

41 Mirant and RRI merged in December 2010 to form GenOn. Our analysis spans the time period before and after the merger, prior to which RRI and Mirant are tracked as separate companies and after which our reported results reflect the performance of the merged company. See GenOn (2010).

42 Brealey, *et al.* (2011), p. 193.

43 Treasury yields of 4/27/2011 from Bloomberg (2011).

44 Ibbotson (2011), Table A-1 and Dimson, *et al.* (2010), Table 10.

45 The security's beta is measured as the covariance of the stock price and market index divided by the variance of the market index. A beta of 1 implies that, on average, when the market moves 1%, the company's stock moves 1% as well. A company with a beta of 2 is more volatile because, on average, its share price moves 2% with a 1% move in the market. We calculated betas for each company by averaging 5-year weekly betas starting Mondays, Wednesdays, and Fridays .

Table 41
Merchant Generation Company Return on Equity

Merchant Generation Company	Risk Free Rate (%) [1]	Market Risk Premium (%) [2]	Beta [3]	Return on Equity (%) [4]
NRG Energy, Inc.	4.3%	6.5%	1.10	11.4%
GenOn Energy Inc (fka RRI Energy)	4.3%	6.5%	1.73	15.6%
Calpine Corp.	4.3%	6.5%	1.29	12.7%
GenOn Energy Holdings Inc (fka Mirant)	4.3%	6.5%	1.08	11.3%
Dynegy, Inc.	4.3%	6.5%	1.55	14.4%
Value-weighted Portfolio Average	4.3%	6.5%	1.23	12.3%

Sources and Notes:

[1] 15-day average yield of 20-year U.S. Treasury Rate as of 4/25/2011 from Bloomberg (2011).

[2] Average of long-term equity risk premia of 6.7% and 6.3% from Ibbotson[46] and Credit Suisse,[47] respectively.

[3] Five year average of Monday, Wednesday, and Friday weekly betas from Bloomberg (2011). RRI Energy and Mirant betas are as of 4/9/2010, one week before merger announcement. Dynegy beta is as of 8/6/2010, one week before Blackstone's tender offer.

[4] [1] + [2] x [3] .

b. Cost of Debt

We estimated the cost of debt by compiling the unsecured senior credit ratings for each of the five merchant generation companies and examining bond yields associated with those credit ratings. In Standard and Poor's ("S&P") credit ratings, a company receives a higher rating based on its ability to meet its financial commitments, with "AAA" being the highest rating and "D" being the lowest.[48] Table 42 shows the S&P credit rating, 5-year average long-term debt, and the corporate bond yield implied by the credit rating for each merchant generation company. The credit rating for four of the companies is "B" while NRG has a rating of "BB," implying that these companies are more risky and vulnerable to adverse business, financial, and economic conditions than are top-rated companies. We calculate the industry bond yield of 8.1% by weighting each company's bond yield by its 5-year average long-term debt.

46 Ibbotson (2011), Table A-1.

47 Dimson, *et al.* (2010), Table 10.

48 Standard & Poor's (2011)

Table 42
Standard & Poor's Credit Ratings for Merchant Generation Companies

Merchant Generation Company	S&P Credit Rating	5-Year Average Long-Term Debt *($m)*	Corporate Bond Yield *(%)*
	[1]	[2]	[3]
NRG Energy, Inc.	BB	$8,847	7.0%
GenOn Energy Inc (fka RRI Energy)	B	$2,683	8.5%
Calpine Corp.	B	$10,062	8.5%
GenOn Energy Holdings Inc (fka Mirant)	B	$2,848	8.5%
Dynegy, Inc.	B	$5,149	8.5%
Value-weighted Portfolio Average			8.1%

Sources and Notes:
[1] – [3] Credit ratings, average long-term debt, and corporate bond yield as of 4/25/2011 from Bloomberg (2011).

c. Debt-to-Equity Ratio

Table 43 shows the 5-year average debt-to-equity ratio for each merchant generation company that we examine, as reported in each company's annual 10-K report.

Table 43
5-Year Average Debt-to-Equity Ratios

	Debt/Equity Ratio
NRG Energy Inc	59/41
GenOn Energy Inc (fka RRI Energy)	41/59
Calpine Corp	67/33
GenOn Energy Holdings Inc (fka Mirant)	38/62
Dynegy Inc	66/34
Value-weighted Portfolio Average	56/44

Sources and Notes:
5-year average debt-to-equity ratio from annual 10-K reports, and downloaded from Bloomberg (2011).

d. Estimated After-Tax Weighted-Average Cost of Capital

We estimate the ATWAAC using ROE and cost of debt estimated for each company in Sections VI.C.1.a – b, as well as the debt-to-equity ratio and corporate tax rate reported by each company. The cost of capital is the weighted average of the cost of equity and the cost of debt.[49] To calculate ATWACC, interest is a tax deductible expense for corporations so the after-tax cost is discounted by (1- tax rate). Table 44 shows a summary of these results for each of the merchant generating companies we examined along with the value-weighted average across the portfolio. Table 44 also shows the average and median of ATWAAC values.

49 Brealey, *et al.* (2011), p. 216.

Table 44
Cost of Capital Summary for Merchant Generation Companies

Company	S&P Credit Rating	Equity Beta	Cost of Equity	Debt-to-Equity Ratio	Cost of Debt	Corporate Income Tax Rate	ATWACC
			(%)		*(%)*	*(%)*	*(%)*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
NRG Energy, Inc.	BB	1.10	11.4%	59/41	7.0%	40.0%	7.2%
GenOn Energy Inc (fka RRI Energy)	B	1.73	15.6%	41/59	8.5%	40.0%	11.2%
Calpine Corp.	B	1.29	12.7%	67/33	8.5%	40.0%	7.6%
GenOn Energy Holdings Inc (fka Mirant)	B	1.08	11.3%	38/62	8.5%	40.0%	8.9%
Dynegy, Inc.	B	1.55	14.4%	66/34	8.5%	40.0%	8.3%
Average							8.6%
Median							8.3%
Value-weighted Portfolio Average		1.23	12.3%		8.0%	40.0%	8.1%

Sources and Notes:
Bloomberg (2011).
[1] S&P unsecured senior credit ratings as of April 2011 from Bloomberg (2011).
[2] Five-year average of Monday, Wednesday, and Friday weekly betas from Bloomberg (2011).
RRI Energy and Mirant betas are as of 4/9/2010, one week before merger announcement.
Dynegy beta is as of 8/6/2010, one week before Blackstone's tender offer.
[3] From Table 41.
[4] 5-year average debt-to-equity ratio from annual 10-K reports, and downloaded from Bloomberg (2011).
[5] Table 24.
[6] KPMG (2010), p. 26.
[6] [3] x [4] + [5] x [4] x (1 – [6]), Brealey, *et al.* (2011), p. 216.

2. Cost-of-Capital Estimates from Industry Analysts and Fairness Opinions

We compared our estimates of ATWACC to industry analysts and fairness opinions for the companies in our portfolio, as well as other merchant generation segments of publically-traded companies. Analyst estimates range from 7.1% to 12% ATWACC, with most estimates within 8.0% to 9.0%. These numbers are in line with our value-weighted portfolio average of 8.1%. Table 45 shows the industry analysts and fairness opinions by company.

Table 45
ATWACC Estimates from Industry Analysts/Fairness Opinions

		ATWACC Estimates [1]
NRG Energy Inc	[1]	7.1%
GenOn Energy Inc (fka RRI Energy)	[2]	8.5% - 9.5%
Calpine Corp	[3]	7.5%
GenOn Energy Holdings Inc (fka Mirant)	[4]	8.5% - 9.5%
Dynegy Inc	[5]	8.0% - 12.0%
FirstEnergy Merchant Generation	[6]	8.0% - 9.0%
Allegheny Merchant Generation	[7]	8.0% - 8.5%
Duke's Merchant Generation	[8]	8.2% - 9.2%

Sources and Notes:

[1] Cohen, Jonathan, and Greg Gordon (2010a), p. 7.
[2] Mirant Corp. And RRI Energy (2010), p. 42.
[3] Cohen, Jonathan, and Greg Gordon (2010b), p. 7.
[4] Mirant Corp. And RRI Energy (2010), p. 48.
[5] Dynegy Inc. (2010), p. 48.
[6] FirstEnergy Corp. and Allegheny Energy (2010), p. 85.
[7] FirstEnergy Corp. and Allegheny Energy (2010), p. 84.
[8] Duke Energy Corporation (2011), p. 102.

3. After-Tax Weighted-Average Cost of Capital Estimate

We considered both the value-weighted portfolio and recent ATWACC estimates in order to calculate ATWACC for the CONE study. We chose a ATWAAC of 8.5%, 40 basis points higher than the value-weighted portfolio average that reflects a 50/50 debt-to-equity ratio, a 12.5% return on equity, and a 7.5% return on debt. The ATWAAC of our recommendation has a slightly higher expected rate of return when compared to the value-weighted portfolio average, which reflects the business risk of the entire portfolio of contracts and the entire generation fleet of different technologies, fuel types, and locations. Table 46 shows a summary of the merchant generation companies, as well as our recommendation for ATWACC of 8.5%, which is consistent with the median of the ATWACC estimates (including the midpoints of the Analysts' ranges) reported in the bottom half of Table 46.

Table 46
Summary of Recommended Financial Parameters

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%**	

Sources and Notes:
[1] Table 42
[2] Table 41
[3] Table 42
[4] Table 43
[5] Table 44
[6] Table 45

D. INTEREST DURING CONSTRUCTION

Because the construction of a CC or a CT power plant takes a few years, the interest on debt used to fund the power plant construction is required by tax law to be capitalized (*i.e.*, added to the depreciable cost basis) prior to energy production, and amortized over time once production starts. The IDC can be computed on the actual interest expenses traceable to the construction of the power plant, or the interest on a theoretical amount of debt that would have been avoidable but for the construction project. For modeling purposes, we assume that the power plant construction would be funded at the same debt ratio (50%) and debt cost (7.5%) as in the operation phase.

VII. SUMMARY OF CAPITAL, FIXED, AND LEVELIZED COSTS

In this Section, we summarize capital and fixed annual operating costs developed in Sections IV and V, reporting the resulting total plant costs. Based on these costs and the financial assumptions developed in Section VI, we report our resulting level-real and level-nominal CONE estimates. We report these levelized CONE estimates for each CONE Area for the selected reference technology as well as for select sensitivity cases regarding plant technology.

A. TOTAL CAPITAL COSTS

Table 47 and Table 48 contain a summary of the total plant capital costs estimated in Section IV for the simple-cycle and combined-cycle reference plants respectively for a June 1, 2015 on-line date. We report these numbers as overnight costs as well as total capital costs after accounting for interest during construction ("IDC").

Table 47
Simple-Cycle Capital Costs for 2015/16

	CONE Area					CONE Area				
	1	**2**	**3**	**4**	**5**	**1**	**2**	**3**	**4**	**5**
	EMAAC	**SWMAAC**	**RTO**	**WMAAC**	**DOM**	**EMAAC**	**SWMAAC**	**RTO**	**WMAAC**	**DOM**
	($m)	*($m)*	*($m)*	*($m)*	*($m)*	*($/kW)*	*($/kW)*	*($/kW)*	*($/kW)*	*($/kW)*
Plant Proper Costs										
EPC Contract	$130.6	$105.0	$113.6	$123.0	$104.0	$335.1	$269.5	$291.5	$315.8	$265.3
Owner Furnished Equipment	$114.5	$114.5	$111.5	$114.5	$93.0	$293.9	$293.9	$286.2	$293.9	$237.2
OFE and EPC Sales Tax	$10.4	$8.9	$9.8	$8.9	$6.5	$26.6	$22.8	$25.2	$22.8	$16.5
Owner's Costs										
Land	$3.9	$3.6	$2.4	$2.7	$3.5	$9.9	$9.2	$6.2	$6.9	$9.0
Emissions Reduction Credits	$0.7	$0.7	$0.7	$0.6	$0.0	$1.7	$1.7	$1.7	$1.5	$0.0
Gas Interconnection	$16.0	$16.0	$16.0	$16.0	$16.0	$41.1	$41.1	$41.1	$41.1	$40.8
Electric Interconnection	$11.0	$11.0	$11.0	$11.0	$11.0	$28.2	$28.2	$28.2	$28.2	$28.1
Net Start-up Fuel Costs	$2.2	$3.9	$4.1	$3.9	$3.9	$5.7	$10.0	$10.4	$10.0	$10.0
Mobilization and Start-up	$1.2	$1.1	$1.1	$1.1	$1.0	$3.0	$2.8	$2.9	$2.8	$2.5
Project Development	$6.0	$6.0	$6.0	$6.0	$6.0	$15.4	$15.4	$15.4	$15.4	$15.3
Financing Fees	$3.0	$2.7	$2.8	$2.9	$2.4	$7.6	$6.9	$7.1	$7.4	$6.2
Owner's Contingency	$9.0	$8.2	$8.4	$8.7	$7.4	$23.0	$21.0	$21.5	$22.4	$18.9
Total Overnight Costs	**$308**	**$282**	**$287**	**$299**	**$255**	**$791**	**$723**	**$737**	**$768**	**$650**
Interest During Construction	$14.0	$12.7	$10.9	$13.5	$11.5	$36.0	$32.6	$27.8	$34.5	$29.4
Total Capital Costs	**$322**	**$294**	**$298**	**$313**	**$266**	**$827**	**$755**	**$765**	**$803**	**$679**

Sources and Notes:
Plant proper costs estimated by CH2M HILL Engineers, Inc. (2011).
Owner's costs estimated in Section IV.B

Table 48
Combined-Cycle Capital Costs for 2015/16

	CONE Area					CONE Area				
	1	2	3	4	5	1	2	3	4	5
	EMAAC	SWMAAC	RTO	WMAAC	DOM	EMAAC	SWMAAC	RTO	WMAAC	DOM
	($m)	*($m)*	*($m)*	*($m)*	*($m)*	*($/kW)*	*($/kW)*	*($/kW)*	*($/kW)*	*($/kW)*
Plant Proper Costs										
EPC Contract	$356.2	$274.6	$334.9	$333.4	$274.4	$543.3	$418.8	$510.8	$508.6	$418.5
Owner Furnished Equipment	$176.0	$176.0	$173.0	$176.0	$176.0	$268.4	$268.4	$263.9	$268.4	$268.4
OFE and EPC Sales Tax	$18.8	$16.1	$18.3	$16.1	$13.4	$28.7	$24.5	$27.8	$24.6	$20.4
Owner's Costs										
Land	$5.2	$4.8	$3.2	$3.6	$4.7	$7.9	$7.3	$4.9	$5.5	$7.2
Emissions Reduction Credits	$1.6	$1.3	$1.6	$1.4	$0.0	$2.4	$2.0	$2.5	$2.1	$0.0
Gas Interconnection	$16.0	$16.0	$16.0	$16.0	$16.0	$24.4	$24.4	$24.4	$24.4	$24.4
Electric Interconnection	$15.5	$15.5	$15.5	$15.5	$15.5	$23.6	$23.6	$23.6	$23.6	$23.6
Net Start-up Fuel Costs	-$2.7	$1.7	$2.6	$1.7	$1.7	-$4.0	$2.5	$3.9	$2.5	$2.5
Mobilization and Start-up	$2.9	$2.7	$2.8	$2.6	$2.6	$4.4	$4.1	$4.2	$4.0	$4.0
Project Development	$8.0	$8.0	$8.0	$8.0	$8.0	$12.2	$12.2	$12.2	$12.2	$12.2
Financing Fees	$6.0	$5.2	$5.8	$5.7	$5.1	$9.1	$7.9	$8.8	$8.8	$7.8
Owner's Contingency	$18.1	$15.7	$17.4	$17.4	$15.5	$27.6	$23.9	$26.6	$26.5	$23.7
Total Overnight Costs	**$621**	**$537**	**$599**	**$597**	**$533**	**$948**	**$820**	**$914**	**$911**	**$813**
Interest During Construction	$37.0	$31.9	$35.4	$35.2	$31.5	$56.4	$48.6	$53.9	$53.7	$48.0
Total Capital Costs	**$658**	**$569**	**$634**	**$633**	**$564**	**$1,004**	**$868**	**$968**	**$965**	**$861**

Sources and Notes:
Plant proper costs estimated by CH2M HILL Engineers, Inc. (2011).
Owner's costs estimated in Section IV.B

B. TOTAL FIXED O&M COSTS

Table 47 and Table 48 contain a summary of the fixed ongoing annual plant costs estimated in Section V for the simple-cycle and combined-cycle reference plants respectively. The costs reported here are the first-year FOM costs for the first operating year starting in 2014/15. Each of these costs increases with inflation over the economic life of the plant.

Table 49
Simple-cycle Fixed O&M Costs

	CONE Area					CONE Area				
	1	2	3	4	5	1	2	3	4	5
	EMAAC	SWMAAC	RTO	WMAAC	DOM	EMAAC	SWMAAC	RTO	WMAAC	DOM
	($m/y)	*($m/y)*	*($m/y)*	*($m/y)*	*($m/y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Property Tax	$0.2	$0.4	$0.0	$0.1	$0.0	$0.4	$0.9	$0.1	$0.3	$0.0
Insurance	$1.8	$1.8	$1.8	$1.8	$1.8	$4.5	$4.5	$4.5	$4.5	$4.5
O&M Services	$2.7	$2.5	$2.6	$2.5	$2.5	$7.0	$6.5	$6.7	$6.4	$6.4
Asset Management	$1.5	$1.5	$1.5	$1.5	$1.5	$3.9	$3.9	$3.9	$3.9	$3.8
Total Fixed O&M Costs	**$6.1**	**$6.2**	**$5.9**	**$5.9**	**$5.7**	**$15.7**	**$15.8**	**$15.2**	**$15.1**	**$14.7**

Sources and Notes:
Property tax, insurance, and asset management costs estimated in Section V.
O&M services estimated by Wood Group (2011).

Table 50
Combined-cycle Fixed O&M Costs

	CONE Area					CONE Area				
	1	2	3	4	5	1	2	3	4	5
	EMAAC	SWMAAC	RTO	WMAAC	DOM	EMAAC	SWMAAC	RTO	WMAAC	DOM
	($m/y)	*($m/y)*	*($m/y)*	*($m/y)*	*($m/y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Property Tax	$0.2	$0.6	$0.1	$0.2	$0.0	$0.3	$0.9	$0.1	$0.3	$0.0
Insurance	$3.8	$3.8	$3.8	$3.8	$3.8	$5.7	$5.7	$5.7	$5.7	$5.7
O&M Services	$5.4	$5.0	$5.2	$4.9	$4.9	$8.3	$7.7	$7.9	$7.5	$7.4
Asset Management	$1.5	$1.5	$1.5	$1.5	$1.5	$2.3	$2.3	$2.3	$2.3	$2.3
Total Fixed O&M Costs	**$10.9**	**$10.9**	**$10.5**	**$10.4**	**$10.1**	**$16.7**	**$16.6**	**$16.0**	**$15.8**	**$15.4**

Sources and Notes:
Property tax, insurance, and asset management costs estimated in Section V.
O&M services estimated by Wood Group (2011).

C. LEVELIZED COST OF NEW ENTRY

As discussed in Section IV.A.3 of our concurrently prepared 2011 RPM performance review ("2011 RPM Report"),[50] translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how net revenues are received over time to recover capital and annual fixed costs. Level-nominal cost recovery assumes that net revenues will be constant in nominal terms (*i.e.*, decreasing in real dollar, inflation-adjusted terms) over the 20-year economic life of the plant. A level-real cost recovery path starts at a lower level then increases at the rate of inflation (*i.e.*, constant in real dollar terms). As we explain in our 2011 RPM Report, we find that level real is more consistent with our expected trajectory of operating margins from future capacity and net E&AS revenues.[51]

As discussed in the 2011 RPM Report, we recommend that PJM and its stakeholders transition toward using a level-real CONE for MOPR purposes, and we conditionally recommend the same for defining the VRR curve. We recommend maintaining level nominal for the VRR curve until our recommendations to increase the VRR curve cap and calibrate the administrative E&AS offset are adopted. Until then, using the higher level-nominal CONE will help mitigate some of the RPM performance risks we identified.

Table 51 and Table 52 show summaries of our capital costs, annual fixed costs, and levelized CONE estimates for the gas CT and CC reference plants for the 2015/16 delivery year. Our levelization calculation, after accounting for financing costs, depreciation, and IDC, results in a capital charge rate of 11.9% to 12.2% for the CC on a level-real basis (14.8% to 15.0% level nominal) AND 12.9% to 13.1% for the CT on level-real basis (15.8% to 16.0% level nominal).[52] For comparison, the tables also report the results of the CONE studies used as the basis for PJM's current parameters after escalating at inflation to a 2015/16 delivery year. We also report the most recent 2014/15 PJM administrative CONE parameters, inflation-adjusted for the 2015/16 delivery year.

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50 See Pfeifenberger and Newell, *et al.* (2011).

51 Historically, the average CT cost inflation exceeded CPI by 60 basis points while heatrate improvements saved approximately 50 basis points, for a net growth rate in net operating revenues approximately equal to general inflation. *Id.*

52 The capital charge rate is defined as the levelized CONE (without FOM) divided by the overnight capital costs.

The Eastern Mid-Atlantic Area Council ("MAAC") and Western MAAC regions have the highest CONE estimates at $112/kW-year ($307/MW-day) and $109/kW-year ($298/MW-day) respectively on a level real basis. The Southwest MAAC and Rest of RTO Areas are somewhat lower, both at $103/kW-year ($283/MW-day), primarily because of non-union labor availability in Southwest MAAC and avoidance of dual-fuel capability in the Rest of RTO region. The lowest CONE estimate is in Dominion at $93/kW-year ($254/MW-day), which has relatively lower costs because of non-union labor as well as the assumption that the plant can be operated without an SCR.

For comparison, we also present estimates provided by Power Project Management ("PPM") in their 2008 CONE study. After escalating with inflation to 2015 dollars, the PPM level-nominal estimates are $19-23/kW-year ($53-62/MW-day) higher than our estimates in the three CONE Areas reported. The lower capital costs in our study are related primarily to reductions in equipment, materials, and labor costs since 2008, as well as the substantially larger size of the GE 7FA.05 turbine now available compared to the previous GE7FA.03 turbine model. Finally, Table 51 also shows the CONE value PJM has applied in its recent auction for the 2014/15 delivery year, escalated for one year of inflation to represent 2015/16 dollar values.

Table 51
Recommended CONE for Gas CT Plants in 2015/16

CONE Area	**Total Plant Capital Cost**	**Net Summer ICAP**	**Overnight Cost**	**Fixed O&M**	**After-Tax WACC**	**Levelized Gross CONE** Level Real	Level Nominal	**PJM 2014/15 CT CONE**
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$308.3	390	$791.2	$15.7	8.47%	$112.0	$134.0	$142.1
2 Southwest MAAC	$281.5	390	$722.6	$15.8	8.49%	$103.4	$123.7	$131.4
3 Rest of RTO	$287.3	390	$737.3	$15.2	8.46%	$103.1	$123.5	$135.0
4 Western MAAC	$299.3	390	$768.2	$15.1	8.44%	$108.6	$130.1	$131.4
5 Dominion	$254.7	392	$649.8	$14.7	8.54%	$92.8	$111.0	$131.5
Power Project Management, LLC 2008 Update								
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)								
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%	n/a	$154.4	n/a
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%	n/a	$142.8	n/a
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%	n/a	$146.1	n/a

As shown in Table 52, Eastern MAAC has the highest CC CONE at $141/kW-year ($385/MW-day) on a level-real basis, while Rest of RTO and Western MAAC are a bit lower, both at $135/kW-year ($370/MW-day). Southwest MAAC and Dominion have the lowest CONE estimates at $123/kW-year ($338/MW-day) and $120/kW-year ($329/MW-day) respectively, due primarily to non-union labor rates in those locations. Our estimates are $6 to 12/kW-year ($17 to 32/MW-day) below the inflation-adjusted Pasteris Energy CONE estimates on a level-nominal basis primarily due to a higher ICAP rating and lower equipment, materials, and labor costs since 2008 relative to inflation. Our higher plant ICAP rating is due to the larger size of the GE 7FA.05 turbine compared to the GE7FA.04 turbine model examined by Pasteris, as well as the greater duct-firing capability in the plant we examined and lower equipment, materials, and labor costs since 2008. Table 52 also shows the CC CONE value PJM has utilized for the 2014/15 delivery year, inflation-adjusted to 2015/16 dollar values.

Table 52
Recommended CONE for Gas CC Plants in 2015/16

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CC CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$621.4	656	$947.8	$16.7	8.47%	$140.5	$168.2	$179.6
2 Southwest MAAC	$537.4	656	$819.6	$16.6	8.49%	$123.3	$147.6	$158.7
3 Rest of RTO	$599.0	656	$913.7	$16.0	8.46%	$135.5	$162.2	$168.5
4 Western MAAC	$597.4	656	$911.2	$15.8	8.44%	$135.2	$161.8	$158.7
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8	$158.7
Pasteris 2011 Update								
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)								
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%	n/a	$179.6	n/a
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%	n/a	$158.7	n/a
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%	n/a	$168.5	n/a

In addition to our recommended CC and CT CONE estimates in the previous tables, we also developed CONE estimates for select sensitivity cases. Table 53 shows a summary of these CONE estimates for alternative configurations of plants we considered. For both the CT and CC plants in the Rest of RTO, we estimated alternative dual-fuel cases. Adding dual-fuel capability adds $19 million in costs for the CT and $18 million for the CC. For the CT we also developed sensitivity estimates with an SCR in Dominion (increasing costs by $24 million) and without an SCR in the other CONE Areas (decreasing costs by $23-27 million).

Table 53
Additional Sensitivity Case CONE Estimates for 2015/16

Cone Area	Total Plant Capital Cost *($M)*	Net Summer ICAP *(MW)*	Overnight Cost *($/kW)*	Fixed O&M *($/kW-y)*	After-Tax WACC *(%)*	Levelized Gross CONE Level Real *($/kW-y)*	Levelized Gross CONE Level Nominal *($/kW-y)*
Gas CT - No SCR - Dual Fuel							
1 Eastern MAAC	$281.1	392	$717.0	$15.6	8.47%	$102.9	$123.2
2 Southwest MAAC	$258.1	392	$658.4	$15.7	8.49%	$95.6	$114.4
3 Rest of RTO	$279.2	392	$712.1	$15.1	8.46%	$101.7	$121.7
4 Western MAAC	$272.4	392	$694.8	$15.0	8.44%	$99.7	$119.3
Gas CT - With SCR - Dual Fuel							
3 Rest of RTO	$306.2	390	$786.0	$15.2	8.46%	$110.7	$132.5
5 Dominion	$279.0	390	$716.1	$14.7	8.54%	$100.8	$120.6
Gas CT - No SCR - Single Fuel							
3 Rest of RTO	$260.6	392	$664.9	$15.1	8.46%	$94.5	$113.2
Gas CC - With SCR - Dual Fuel							
3 Rest of RTO	$616.7	656	$940.6	$16.0	8.46%	$138.9	$166.3

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LIST OF ACRONYMS

ATWACC	After-Tax Weighted-Average Cost Of Capital
CAPM	Capital Asset Pricing Model
BACT	Best Available Control Technology
BOP	Balance of Plant
CC	Combined Cycle
CONE	Cost of New Entry
CPI	Consumer Price Index
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
E&AS	Energy and Ancillary Services
EPC	Engineering, Procurement, and Construction
FERC	Federal Energy Regulatory Commission
FFS	Factored Fired Starts
FFH	Factored Fired Hours
fka	Formerly Known As
FOM	Fixed Operation and Maintenance
GSU	Generator Step-Up
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
LAER	Lowest Achievable Emissions Rate
LHV	Lower Heating Value
LTSA	Long-Term Service Agreement
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Megawatt-Hours
NAAQS	National Ambient Air Quality Standards
NNSR	Non-Attainment New Source Review
NSR	New Source Review

OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OFR	Owner-Furnished Equipment
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PPM	Power Project Management
PSD	Prevention of Significant Deterioration
RPM	Reliability Pricing Model
SCR	Selective Catalytic Reduction
VOM	Variable Operation and Maintenance
VRR	Variable Resource Requirement

APPENDIX A. CH2M HILL SIMPLE-CYCLE COST ESTIMATES

CH2M HILL's detailed engineering cost estimates for plant proper costs including both EPC contractor costs and owner-furnished equipment costs are contained in this appendix for each simple-cycle plant configuration examined. A summary report describing detailed plant specifications and summary cost results for each CT configuration in each CONE Area is contained in CH2M HILL's summary report in Appendix A.1. Plant layout drawings, project schedules, cost estimate details, and cash flow schedules were also provided for each CT location and configuration. Appendices A.2 through A.5 contain this detailed supporting information for one of the CONE Area 1 plant configuration, which is a dual-fuel plant with an SCR.

APPENDIX A.1. SIMPLE-CYCLE PLANT PROPER COST ESTIMATE REPORT

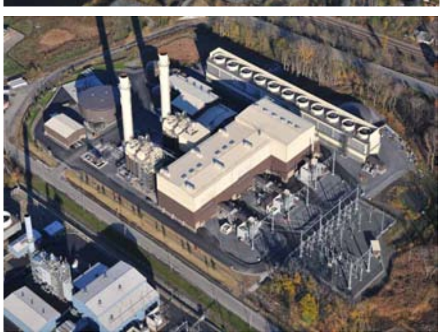
APPENDIX A.2. LAYOUT DRAWING FOR DUAL-FUEL CT WITH SCR

APPENDIX A.3. PROJECT SCHEDULE FOR DUAL-FUEL CT WITH SCR

APPENDIX A.4. COST DETAIL FOR CT WITH SCR IN CONE AREA 1

APPENDIX A.5. CASH FLOW SCHEDULE FOR CT WITH SCR IN CONE AREA 1

APPENDIX A.1. SIMPLE-CYCLE PLANT PROPER COST ESTIMATE REPORT



Simple Cycle Cost Estimate
2 x 0 GE 7FA Reference Plant

Brattle Group
PJM Estimating Support

Prepared By CH2M HILL
Project No. 421147
Rev. C
August 2011

CH2MHILL

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Revision	Description	Date
A	Issued for Review	July 1, 2011
B	Comments Incorporated	August 2, 2011
C	Final	August 23, 2011

1.0 Executive Summary

CH2M HILL Engineers, Inc. was engaged by the Brattle Group, Inc to provide capital cost estimates for gas fuel only and dual fuel (oil & natural gas) GE Frame 7FA.05 gas turbine simple cycle power plants at multiple sites, each capable of generating approximately 420 MW. The plant configurations each will consist of two (2) GE Frame 7FA.05 combustion turbine generators (CTGs), and all necessary Balance of Plant (BOP) equipment. Each plant will be capable of producing approximately 420 MW. Cost estimates were provide for simple cycle plants both with and without SCR in the combustion turbine exhausts.

Dual Fuel Combustion Turbines

As a basis for the dual fuel combustion turbine estimates CH2M HILL developed the following information:

- Capital costs for five (5) geographical areas (New Jersey, Maryland, Illinois, Pennsylvania, and Virginia)
- A General Arrangement drawing for a representative simple cycle power plant
- A Level One Project schedule
- A basic monthly cash flow tabulation

The capital cost estimates for the dual fuel combustion turbine (without SCRs) alternative for each geographical area are included in the table below. The details of the cost breakdown for each location are included in Section 6. Note these costs are exclusive of the change in cash flows at assignment of OFE and NTP to EPC contractor.

No SCR

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
New Jersey	Union	126,012,137	102,043,367	228,055,504
Maryland	Non-Union	104,153,617	100,742,702	204,896,319
Illinois	Union	123,709,817	102,042,993	225,752,810
Pennsylvania	Union	118,716,860	100,752,855	219,469,715
Virginia	Non-Union	103,989,281	99,452,320	203,441,601

The capital cost estimates for the dual fuel combustion turbine with SCR alternative for each geographical area are included in the table below. The details of the cost breakdown for each location are included in Section 6. Note these costs are exclusive of the change in cash flows at assignment of OFE and NTP to EPC contractor.

With SCR

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
New Jersey	Union	130,552,074	124,864,072	255,416,146
Maryland	Non-Union	104,991,119	123,371,532	228,362,651
Illinois	Union	128,276,002	124,863,686	253,139,688
Pennsylvania	Union	123,045,308	123,384,930	246,430,238
Virginia	Non-Union	104,760,187	121,893,014	226,653,201

__Gas Fuel Only Combustion Turbines__

As a basis for the gas fuel only combustion turbine estimate CH2M HILL developed the following information:

- Capital cost for the Will County, Illinois location
- A General Arrangement drawing for a representative simple cycle power plant
- A Level One Project schedule
- A basic monthly cash flow tabulation

The capital cost estimate for the natural gas fuel combustion turbine without SCR for Will County, Illinois is included in the table below. The detail of the cost breakdown for this location is included in Section 6. Note these costs are exclusive of the change in cash flows at assignment of OFE and NTP to EPC contractor.

No SCR

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
Illinois	Union	109,437,632	98,513,712	207,951,344

The capital cost estimate for the gas fuel only combustion turbine with SCR for Will County, Illinois is included in the table below. The detail of the cost breakdown for this location is included in Section 6. Note these costs are exclusive of the change in cash flows at assignment of OFE and NTP to EPC contractor.

With SCR

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
Illinois	Union	113,572,247	121,323,142	234,895,389

2.0 Development Approach

2.1 Estimating Process

For the development of the capital cost estimate, CH2M HILL utilized our Power Plant Indicative Cost Estimating Methodology which is based upon the plant specific configuration, location specific productivity and labor cost factors, and our extensive current cost data base for equipment and material. These factors are processed using our proprietary Indicative Estimating Software Model to produce a detailed analysis of the cost elements for the project that are then compared to recently completed similar projects.

Project Configurations

CH2M HILL's experience with various plant configurations is extensive. The combustion turbines shown in the table below have been designed and installed in combined cycle, simple cycle and cogeneration modes.

- 1 X LMS 100 simple cycle
- 2 X F-class simple cycle
- 4 X LM 6000 simple cycle
- 12 X FT-8 Twin Pack simple cycle
- 1 X 1 F-class combined cycle
- 2 X 1 F-class combined cycle
- 3 X 1 E-class combined cycle

CH2M HILL's estimating team retains standard plant layout configurations that have been imported into the estimating data base for use in this study. The design basis for this study is a 2 x 0 - 7F class simple cycle plant, the details for which are defined in Sections 3.0 – Plant Scope and Section 4.0 – General Arrangement of this report.

Variability by Location

The US construction industry has the most variability in productivity and execution strategy by location than any other country in the world. Project execution ranges from strong union locations such as New York City, Chicago, San Francisco and St. Louis to lower cost, merit shop locations such as the Gulf Coast and Southeast US. CH2M HILL's historical database tracks and updates labor productivity by location. CH2M HILL's "base" productivity location is the Gulf Coast, like many national contractors. At that location, the base productivity for each discipline trade is considered a 1.0 productivity factor and is considered the most efficient location to perform work based on worker skills and efficiency. That 1.0 productivity factor is then adjusted to reflect union labor, local labor rules and other historical data.

Variability of Estimates for Material and Equipment

Certain material and equipment costs are more volatile in the heavy industrial market than others. As examples, high temperature- high pressure pipe, electrical transformers and copper wire are high in demand in the oil & gas market as well as the power market. When both industries are busy, costs increase dramatically due to not only material and manufacturing costs, but also due to greater demand than supply. Market conditions sometimes make it nearly impossible to assess with any certainty the proper amount of escalation to apply to some materials and equipment. This is compounded by the extended time from estimate development to project implementation. CH2M HILL's constant activity in bidding and procuring material and equipment provides more accurate costs that reflect current market conditions than available by other means.

CH2M HILL's Indicative Estimating Software Model

CH2M HILL has taken over 20 years of data from our involvement in the power industry and developed an indicative database to aid in estimating future projects. The "Power Indicative Estimating Program" derives project costs based on information that is input on various worksheets within the program from a series of inputs, multiple logic functions and iterations, and a preliminary Indicative Estimate is produced which can be reviewed and modified as necessary.

Power Indicative Estimating Program Output

Once a project configuration, location, schedule and execution model is defined, the indicative estimator works with a Power Project Engineer to reflect other project properties unique to the project. The estimator inputs the specific project data into the model and then reviews with experienced construction managers and engineers to confirm alignment. The program produces an estimating basis and a series of outputs. Some of these outputs include:

- Quantities of concrete, structural steel, pipe, conduit, cable and insulation
- Equipment required by system
- Work-hours for labor by discipline
- Engineering hours
- Construction supervision hours
- Startup and testing hours
- Indirect labor and equipment

The program allows the estimator to input the latest labor rates, productivity, which is then tabulated in the program to develop the final cost of the plant. The results of these analyses are contained in Section 6.0 of this report.

2.2 Owner Cost Estimates

Pricing for the Combustion Turbine Generators (CTGs), is based on GE Power Island information obtained from similar plants CH2M HILL has constructed and proposed. Note that GE's scope includes the Continuous Emissions Monitoring System (CEMS), Packaged Electrical and Electronic Control Cab (PEECC), the Plant Distributed Control System (DCS) and the CTGs auxiliary equipment. For plants with SCR, budgetary quotes were received from major SCR system suppliers and one representative design was used for pricing data.

These components (Owner Furnished Equipment or OFE) are procured by the Owner at project start, prior to EPC contract NTP. They are assigned to the EPC contractor at that time. Estimates of Owner costs that are in addition to the EPC contract cost are tabulated in Section 6.0.

2.3 EPC Cost Estimate

Pricing for the major Balance of Plant equipment including the generator step-up transformers were obtained from actual pricing and budgetary quotes received from vendors for similar recent projects and proposals. The plant construction cost estimates were developed based on data from recent EPC projects. Labor rates and productivity factors for the following five (5) geographical areas were verified and used to develop the direct and indirect costs.

- 1) Middlesex County, New Jersey
- 2) Charles County, Maryland
- 3) Will County, Illinois
- 4) Northampton County, Pennsylvania
- 5) Fauquier County, Virginia

The construction cost estimates are based on direct labor hire (concrete, steel, piping, electrical and instrumentation) and specialty subcontract union (locations 1, 3, and 4) and merit shop craft labor (locations 2 and 5). Quantities for bulks were determined from plants similar in size and configuration. Historical data was utilized to provide an overall parametric check of account values of the completed estimate.

Labor

Locations 1, 3, and 4: Union craft labor rates were determined from prevailing wages for the area. Rates were built-up including the base rate, fringes and legalities. The estimate is based on a 50 hour craft work week. A labor factor of 1.1 was applied to the CSA accounts, 1.3 for the piping accounts, and 1.2 on all other accounts and based on various factors including location, working in an existing facility, congestion, local labor conditions, weather and schedule.

Locations 2 and 5: Merit shop craft labor rates were determined from prevailing wages for the area. Rates were built-up including the base rate, fringes and legalities. The estimate is based on a 50 hour craft work week. A labor factor of 1.0 was applied to all accounts based on various factors. A $50 per day per diem has been included.

Escalation

The cost estimates are provided in June 2011 dollars and escalation was included based on the following schedules.

- Craft labor was escalated at 4.0% for 2011 and beyond.
- Engineered equipment and bulk materials were escalated at 6% for 2011 and beyond.
- Professional labor and construction indirect expenses were escalated at 3% for 2011 and 4% for 2012 and beyond.
- Specialty subcontracts were escalated at 5% for 2011 and beyond.

Contingency & Gross Margin

Contingency was included at:

- 5% for Professional Labor, Material and Construction Equipment
- 7% for Craft Labor
- 6% for Specialty Subcontracts
- 2% for the CTGs and STG
- 3% for the HRSGs
- 3% for Engineered Equipment

A gross margin of 10% was applied with 5% assignment fee applied to the Owner Furnished Equipment.

Project Indirects

Project indirects include:

- Builders Risk insurance
- General and excess liability insurance
- Performance and payment bonds
- Construction permits
- Sales tax (not including OFE) to roll up through markups then taken out at bottom line
- Letter of credit in lieu of retention
- Warranty
- Bonus pool

Scope - Inclusions

- Structural and civil works
- Mechanical, electrical, and control equipment
- Electrical Power Distribution Center (pre-assembled & tested)
- Heavy haul (allowance)
- Operator training
- O&M manuals
- Escalation
- Bulks including piping and instrumentation
- Contractor's construction supervision
- Temporary facilities
- Construction equipment, small tools and consumables
- Start-up spare parts and start-up craft labor
- Construction permits allowance ($100,000)
- First fills
- Insurances
- Gross margin
- 5% Letter of Credit in lieu of retention

- Construction power, water and natural gas consumption
- Performance and Payment Bond
- Builders All Risk Insurance (costs broken out from EPC estimate for reference – see Estimate Basis Section 17.0)

Scope - Exclusions

- Soils remediation, moving of underground appurtenances or piping
- Dewatering except for runoff during construction
- Wetland mitigation
- Fuel gas compression
- Noise mitigation measures or study (unless otherwise noted)
- Piling
- Geotechnical investigation and survey (shown separately from EPC estimate as an Owners cost)
- Sales Tax (shown separately from EPC estimates as an Owners cost)
- Permitting/Environmental permits (shown separately from EPC estimates as an Owners cost)
- Fuel oil and natural gas consumption during startup (shown separately from EPC estimate as an Owners cost)
- Switchyard

Scope - Assumptions & Clarifications

- Assumes flat, level and cleared site.
- Assumes free and clear access to work areas.
- This site does not contain any EPA defined hazardous or toxic wastes or any archeological finds that would interrupt or delay the project.
- Spread footings are assumed for all equipment.
- All excavated material is suitable for backfill/compaction.
- Rock excavation is not required.
- Temporary power and water will be available at site boundary as required to support construction at no cost to Contractor.
- An ample supply of skilled craft is available to the site.
- TA services are owner provided as part of their equipment supply.
- Craft bussing is not required.
- Ample space (provided by owner) for craft parking, temporary facilities, laydown and storage is available adjacent to site.
- Field Erected Storage Tanks are carbon steel with internal high build epoxy coatings.
- Access road modifications and improvements (beyond the site boundary battery limit) will be performed by others.
- Roads for heavy haul are suitable for transportation and contain no obstructions for delivery of heavy/oversized equipment.
- Heavy haul is assumed to be from a rail siding within one mile of the plant to setting on foundations.
- Equipment is supplied with manufacturer's standard finish paint.

- Natural gas is delivered at an adequate pressure and no gas compression is required.
- Gas metering station is by others.
- The electrical equipment will be housed in pre-fabricated building.
- The electrical scope concludes at the high side of the Generator Step-up (GSU) transformers. Transmission line and substation costs are by others.
- Heat tracing has not been included for large, above ground process piping where system pumps can be operated to prevent freezing, or where the system can be drained during extended cold weather outages.
- Rental demineralized water treatment trailers.

3.0 Plant Scope

3.1 General Description

The proposed simple cycle power plant has a nominal generating capacity of 420MW at 59 °F outdoor ambient temperature when operating on gas fuel. The major components of the project include two (2) GE Frame 7FA.05 Combustion Turbine Generators (CTGs), air pollution controls and associated auxiliary and control systems. The CTGs will be equipped with inlet evaporative coolers to increase power output at high ambient temperature. The plant (dual fuel CT option) will operate both on natural gas and distillate fuel oil. The CTGs will be equipped with dry-low NOx combustors (gas fuel operation) to reduce NOx emissions. The CTGs will be equipped with water injection for NOx control when operating on distillate fuel (dual fuel option).

The termination points for the power facility are at the battery limits of the facility and include the following:

- High Pressure natural gas supply downstream of the gas metering station (by others) at the power facility boundary
- Water from the municipal water supply at the power facility boundary
- Waste to the municipal sewer at the power facility boundary
- Electrical connection is at the high side of the generator step-up transformers

The facility is assumed to be located on a Greenfield site. There will be one building included in the plant layout: an integrated administration/control room/warehouse/maintenance building. Buildings are of pre-fabricated construction. Layout of the plant shall be in accordance with the General Arrangement drawing included in Section 4.0.

General performance parameters are tabulated below. Predicted emissions data is also provided based on generic data for CTG and SCR performance using estimated stack emissions concentrations and rates.

General Performance

Simple Cycle Plant With SCR/CO

	GAS			
	Evaporative Cooling			
Plant configuration	1x0	2x0	1x0	2x0
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	21,515	21,515	21,515	21,515
CT Generators terminal power, kW	213,280	426,560	198,989	397,978
Total Fuel Input, Btu/Hr	1,902,884,160	3,805,768,320	1,814,381,700	3,628,763,400
Gross Plant Heat Rate, Btu/kWH (LHV)	8,922	8,922	9,118	9,118
Plant Auxiliary Loads, kW	4,399	8,798	4,185	8,370
Net Plant Power, kW	208,881	417,762	194,804	389,608
Net Plant Heat Rate, Btu/kWH (LHV)	9,110	9,110	9,314	9,314

	FUEL OIL			
	Evaporative Cooling			
Plant configuration	1x0	2x0	1x0	2x0
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	18,300	18,300	18,300	18,300
CT Generators terminal power, kW	218,780	437,560	211,867	423,734
Total Fuel Input, Btu/Hr	2,102,700,000	4,205,400,000	2,058,287,900	4,116,575,800
Gross Plant Heat Rate, Btu/kWH (LHV)	9,611	9,611	9,715	9,715
Plant Auxiliary Loads, kW	4,482	8,963	4,378	8,756
Net Plant Power, kW	214,298	428,597	207,489	414,978
Net Plant Heat Rate, Btu/kWH (LHV)	9,812	9,812	9,920	9,920

Simple Cycle Plant No SCR/CO

	GAS			
	Evaporative Cooling			
Plant configuration	1x0	2x0	1x0	2x0
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	21,515	21,515	21,515	21,515

CT Generators terminal power, kW	213,280	426,560	198,989	397,978
Total Fuel Input, Btu/Hr	1,902,884,160	3,805,768,320	1,814,381,700	3,628,763,400
Gross Plant Heat Rate, Btu/kWH (LHV)	8,922	8,922	9,118	9,118
Plant Auxiliary Loads, kW	3,199	6,398	2,985	5,970
Net Plant Power, kW	210,081	420,162	196,004	392,008
Net Plant Heat Rate, Btu/kWH (LHV)	9,058	9,058	9,257	9,257

	FUEL OIL			
	Evaporative Cooling			
Plant configuration	1x0	2x0	1x0	2x0
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	18,300	18,300	18,300	18,300

CT Generators terminal power, kW	218,780	437,560	211,867	423,734
Total Fuel Input, Btu/Hr	2,102,700,000	4,205,400,000	2,058,287,900	4,116,575,800
Gross Plant Heat Rate, Btu/kWH (LHV)	9,611	9,611	9,715	9,715
Plant Auxiliary Loads, kW	3,282	6,563	3,178	6,356
Net Plant Power, kW	215,498	430,997	208,689	417,378
Net Plant Heat Rate, Btu/kWH (LHV)	9,757	9,757	9,863	9,863

Predicted Emissions

GE 7FA.05						
OPERATING CONDITION		**N. Gas**	**Fuel Oil**			
Ambient DBT Deg F		59	59			
Relative Humidity %		60	60			
Gas Turbine Unit Exhaust						
Flow Rate	lbs/hr	4,132,000	4,151,000			
Temperature	deg F	1113	1147			
Argon	% VOL	0.88	0.84			
Nitrogen	% VOL	74.18	70.7			
Oxygen	% VOL	12.26	10.68			
Carbon Dioxide	% VOL	3.85	5.74			
Water	% VOL	8.83	12.04			
Gas turbine Emissions						
NOx corrected to 15% O2	ppmvd	9	42			
NOx as NO2	lbs/hr	69	370			
CO corrected to 15% O2	ppmvd	9	20			
CO	lbs/hr	33	72			
UHC	ppmvd	7	7			
UHC	lbs/hr	16	16			
PM10 particulates	lbs/hr	9	17			

With SCR

	Gas CT	
	N.G (ppmvd)	F.O. (ppmvd)
NO_x	2	5
VOC	5	5
CO	5	11
$PM_{2.5}$	--	--
SO_2	Note A	Note B

	Gas CT	
	N.G (lb/hr)	F.O. (lb/hr)
NO_x	15.6	44.5
VOC	13.5	15.5
CO	23.7	59.5
$PM_{2.5}$	9	17
SO_2	2.7	3.4

	Gas CT	
	N.G (lb/MMBtu)	F.O. (lb/MMBtu)
NO_x	8.20E-03	2.12E-02
VOC	7.09E-03	7.37E-03
CO	1.25E-02	2.83E-02
$PM_{2.5}$	4.73E-03	8.08E-03
SO_2	1.43E-03	1.64E-03

	Gas CT 1X0	
	Natural Gas	Fuel oil
Heat input (MMBtu/hr)	1,903	2,103
Fuel Heating Value Btu/Lb (LHV)	21,515	18,300

Notes

A - 0.5 grains/100 scf

B - 15 ppm on a mass basis for fuel oil

c - Assumed heating value of natural gas of 1000 Btu/scf

3.2 Owner Furnished Equipment (OFE)

The following paragraphs describe the equipment for which the Owner is responsible to purchase.

Combustion Turbine Generators (Power Island Scope) - The combustion turbine generators (CTG's) operate to produce electrical power and waste heat. The plant will include two (2) General Electric 7FA.05 combustion turbine-generators packaged for outdoor installation.

Depending upon the site the combustion turbines will be equipped for gas fuel only operation or dual fuel (distillate fuel & natural gas) fuel operation. Units equipped for distillate fuel operation will require a water injection system for NOx emissions control. The CTG equipment package includes the following accessory systems:

- DLN Combustion System (Natural Gas and Distillate fuel oil)
- Water Injection System (for distillate fuel operation)
- Lube Oil System
- Hydraulic Control Oil Systems
- Water Wash System
- Exhaust System
- Inlet Air Filtration System (with noise abatement)
- Inlet Air Cooling System (evaporative)
- Starting System (with turning gear)
- Dual Fuel Control Systems (gas and distillate fuels)
- Variable Inlet Guide Vane (IGV) System
- Mark VI (TMR) Turbine Control & Protection System
- Packaged Electric and Electronic Control Cab (PEECC)

Distributed Control System (Power Island Scope) - The Distributed Control System (DCS) will be a GE MARK VI Triple Modular Redundant (TMR) control system provided by GE as part of the power island package. The DCS shall provide for the supervisory control of the Combustion Turbine Generators. In addition the DCS shall provide for the control and protection of the Balance of Plant (BOP) equipment, excepting those systems that are better suited for local control such as the Water Treatment System, Instrument Air Dryers, CEMs, and miscellaneous sumps. Where local controls are used, common trouble alarms and supervisory control functions shall be provided by the DCS. Human Machine Interfaces (HMIs) shall be located in the Central Control Room and locally at each major piece of equipment.

Continuous Emissions Monitoring System (Power Island Scope) - A fully certified Continuous Emissions Monitoring System (CEMS) shall be provided (by GE) for each CTG to continuously monitor the emissions from each CTG. A Data Acquisition and Handling System (DAHS) shall be provided capable of logging and reporting emissions as required by the Air Quality Permit. The CEMS and DAHS equipment shall be housed in a temperature and humidity controlled CEMS shelter.

Selective Catalytic Reduction (SCR) - For plants with SCR, the proposed plant includes one SCR assembly with NOx and CO catalyst, ammonia injection system, two tempering air fans, and stack, per turbine.

3.3 EPC Scope

The following paragraphs describe the equipment for which the EPC contractor shall be responsible for procurement.

3.3.1 Gas Fuel Only - Combustion Turbines

Auxiliary Cooling Water System - The auxiliary cooling water system is a closed loop cooling water system supplying cooling water to the gas turbine generator coolers, steam turbine & gas turbine lube oil coolers and other auxiliary equipment. The major equipment includes the following:

- Two (2) 100% Pumps
- Two (2) 50 % Fin – Fan Coolers
- Surge Tank
- Chemical Addition Tank

Auxiliary Electrical System - The auxiliary electrical system provides a means of stepping-down the generator terminal voltage to deliver power to the plant auxiliaries at a reduced voltage. Typical major equipment includes:

- Auxiliary cable and/or bus
- Station unit auxiliary transformers (UAT)
- 5 kV switchgear
- 5kV medium voltage motor controller gear (MVMC)
- Station service transformers (SST)
- secondary unit substations (SUS)
- 480 V motor control centers (MCC)

Cathodic Protection System – The cathodic protection system function to mitigate galvanic action and prevent corrosion on the underground natural gas piping. The major equipment includes:

- Sacrificial anodes
- Cable
- Test boxes for potential measurement
- Insulating flanges.

DC Power System - The DC power system functions to provide a reliable source of motive and control power for critical equipment, the emergency shutdown of the plant, and the egress of plant personnel during blackout conditions. These loads typically include control power for power circuit breakers, switchgear, protective relaying, and power for the Uninterruptible Power Supply (UPS). The major equipment includes:

- A bank of lead acid storage battery
- Two 100% capacity battery chargers
- A DC power distribution switchboard

Emergency Diesel Generator - The emergency diesel generator provides for the supply of essential AC auxiliary power during an electrical system (grid) black-out to permit a safe and orderly shutdown of the plant equipment. The major equipment includes:

- 500 kW diesel generator w/load bank
- 6,000 gallon diesel storage tank

Demineralized Water System - The demineralized water system functions to provide a supply of demineralized make-up water to the CT evaporative cooling system, the CT water injection system (NOx control on distillate fuel), and for some the CT wash water solutions. During operation on distillate fuel oil and/or when operating the CT evaporative cooling system a rental water treatment trailer must be brought in to keep up with the demineralized water demands of the CTs. Major equipment that makes up the demineralized water system includes the following:

- A 2,200,000 gallon demineralized water storage tank for dual fuel CTs
- A 150,000 gallon demineralized water storage tank for gas fuel only CTs
- Two (2) 100% capacity demineralized water transfer pumps
- Water treatment trailers (rental by Owner)

Facility Low Voltage Electrical System - The low voltage electrical system conditions and distributes electrical power at various voltage levels for lighting, receptacles and small loads (motors, HVAC, etc.) as required for all buildings and site support facilities. The major equipment of this system includes:

- Transformers
- Distribution panel boards
- Disconnect switches
- Separately mounted motor starters
- General-purpose receptacles
- Welding receptacles
- Lighting

Fuel Gas Condition Skid- The fuel gas skid functions to filter and heat the natural gas supplied for use as fuel by the combustion turbine. A skid is provided for each CTG. Fuel gas heating is performed during startup and normal operation by an electric heater to provide the superheat necessary to prevent the formation of liquid hydrocarbons in the fuel. The major equipment for each skid includes the following:

- Two (2) 100% coalescing filter/separators
- One (1) 100% scrubber
- One (1) fuel gas electric heater

Fuel Gas Pressure Regulating Skid – A dual train fuel gas pressure regulating skid shall be provided to filter and regulate the supply pressure of the natural gas to the facility to satisfy the operational requirements of the CTGs. The major pressure regulation skid equipment includes the following:

- One (1) emergency shutdown valve
- Two (2) 100% capacity coalescing filter/separators
- Two (2) 100% capacity pressure reducing trains each equipped with the following:
- * One (1) automatic inlet isolation valve per train
- * One (1) startup pressure reducing valve per train

- * One (1) primary pressure reducing valve per train
- One (1) safety relief valve with vent stack
- One (1) fuel gas condensate drains tank

Fire Protection System - The fire protection system provides standpipes and hose stations, fire extinguishers, independent fire detection systems, and fixed carbon dioxide suppression systems to protect personnel, plant buildings and equipment from the hazards of fire. The system consists of the following:

- Low-pressure carbon dioxide fire suppression system
- Fire detection systems
- Portable fire extinguishers
- Manual fire alarm systems
- Manual pull stations in the buildings
- Fire Protection Control Panel for alarm, indication of system status, and actuation of fire protection equipment.
- One (1) 100% electric driven fire pump
- One (1) 100% diesel driven fire pump with diesel day tank.
- One (1) jockey pump
- 100,000 gallons of fire water reserve within the raw water storage tank
- Piping and valves, stand pipes and hose stations
- Fire pump building

Grounding System - The grounding system function to provide protection for personnel and equipment from the hazards that can occur during power system faults and lightning strikes. System design shall include the ability to detect system ground faults. The grounding system shall typically consist of copper-clad ground rods, bare and insulated copper cable, copper bus bars, copper wire mesh, exothermic connections, and air terminals.

Generation (High Voltage) Electrical System- The generation electrical system functions to deliver generator power to the Substation, and provides power for the auxiliary electrical system. One set of the following equipment shall be provided for each the three (3) generating unit).

- Generator main leads
- Generator breaker
- Generator step-up (GSU) transformer (230 kV), (345kV Location 3 Only)
- Auxiliary transformer

Oily Waste System - The Oily Waste system collects oil-contaminated wastewater in the plant drains system. The oil waste system is gravity feed throughout the plant to an oil water separator. The solids and oil collected in this system will be collected for offsite disposal at a suitable, licensed, hazardous waste facility. The effluent from the oil/water separator will be discharged to the local sewer system.

Plant Instrument and Service Air System - The plant instrument and service air system function to supply clean, dry, oil-free air at the required pressure and capacity for all pneumatic controls, transmitters, instruments and valve operators, and clean compressed air for non-essential plant service air requirements. The plant instrument and service air system includes the following components:

- Two (2) full capacity, air cooled, single stage, rotary screw type air compressors, each complete with controls, instrument panel, intercooler, lubrication system, aftercooler, moisture separator, intake filter-silencer, air/oil separator system and an unloading valve.
- Two (2) full capacity air receivers
- Two (2) full capacity, dual tower, heaterless type desiccant air dryers
- Two (2) full capacity pre-filters
- Two (2) full capacity after-filters
- Associated header and distribution piping and valves

Plant Communication System - The plant communication system functions to provide the plant external communication system through the use of the public telephone system. The administration building, control room, maintenance and storage areas will be equipped with telephone jacks. The Owner shall provide any internal plant communication systems including, but not limited to, two-way radios.

Plant Security - The plant security system provides protection to the property and personnel. A security system consisting of card readers, intercoms, motor operated gate and fencing will be provided.

Potable Water - The potable water system serves as a water source for drinking and personnel hygiene needs. Potable water also serves as a water source for eyewash and safety shower stations. Potable Water will be supplied from the local water utility.

Raw Water System - The raw water system provides utility water for general plant use. The water will be provided by the local water utility. The raw water system will supply water for miscellaneous non-potable plant uses including demineralized water treatment system supply, plant equipment wash-downs, general service water and fire water. The major equipment includes the following:

- One (1) 200,000 gallon raw water/fire water storage tank
- Two (2) 100% capacity raw water pumps

Sanitary Waste System - The sanitary waste system collects sanitary wastes from the plant and transports to the city sewer system.

Uninterruptible Power Supply (UPS) - The uninterruptible power supply functions to provide reliable, regulated low voltage ac power to critical equipment during normal and emergency operating conditions. The typical loads that are considered for connection to the UPS include the Distributed Control System (DCS), CEMS, critical instruments, emergency shutdown networks, and critical vendor supplied control panels. The UPS system consists of the following components:

- Static inverter
- Static transfer switch
- Alternate source transformer and line voltage regulator
- Manual make-before-break bypass switch
- Two ac circuit breakers (alternate input, and bypass source)
- One dc circuit breaker
- Vital 120 V ac distribution panel with fused disconnects
- Controls, indicating lights, meters and alarms to control the UPS

3.3.2 Dual Fuel - Combustion Turbines

The following equipment is required to support dual fuel (distillate fuel & natural gas fuel) operation of the combustion turbines. It is in addition to the equipment listed above for gas fuel operation of the combustion turbines:

Fuel Oil System - The fuel oil system receives, stores, regulates and transports distillate oil for use as backup fuel in the combustion turbine. The major equipment includes:

- One (1) 2,000,000 gallon fuel oil storage tank with steel containment
- Two (2) fuel unloading stations
- Two (2) 100% capacity fuel forwarding pumps
- Two (2) 100% capacity fuel transfer pumps
- Interconnecting power and instrument cable, piping valves, filters and accessories

Demineralized Water System – The size of the demineralized water storage tank must be increased to 2,200,000 gallons for the dual fuel combustion turbines to support water injection for NOx control.

3.3.3 Selective Catalytic Reduction (SCR)

The following additional equipment is required to support SCR operation, if SCR is installed with the plant:

Ammonia System - The aqueous ammonia system stores and delivers ammonia to the Selective Catalytic Reduction (SCR) system for the reduction of NOx emissions. The major equipment consists of the following:

- Two (2) 100% ammonia forwarding pumps
- One (1) nominal 20,000 gallon horizontal storage tank
- One (1) evaporator
- Tank truck unloading area

4.0 Power Plant General Arrangement

- Gas Fuel Only Combustion Turbine Arrangement, G-PP-003, revision A
- Dual Fuel Combustion Turbine Arrangement, G-PP-011, revision A

5.0 Project Schedules

Single Fuel Option:

A 23 month overall schedule (NTP-COD) was assumed which includes a 17 month construction/startup schedule through COD.

Project Start	January 1, 2013
NTP and Start of detailed engineering	July 1, 2013
Start of construction	January 1, 2014
COD	June 1, 2015

Single Fuel Option w/SCR:

A 23 month overall schedule (NTP-COD) was assumed which includes a 17 month construction/startup schedule through COD.

Project Start	January 1, 2013
NTP and Start of detailed engineering	July 1, 2013
Start of construction	January 1, 2014
COD	June 1, 2015

Dual Fuel Option:

A 26 month overall schedule (NTP-COD) was assumed which includes a 20 month construction/startup schedule through COD.

Project Start	September 17, 2012
NTP and Start of detailed engineering	April 1, 2013
Start of construction	October 2, 2013
COD	June 1, 2015

Dual Fuel Option w/SCR:

A 26 month overall schedule (NTP-COD) was assumed which includes a 20 month construction/startup schedule through COD.

Project Start	September 17, 2012
NTP and Start of detailed engineering	April 1, 2013
Start of construction	October 2, 2013
COD	June 1, 2015

Prior to the NTP the Owner must obtain all the necessary environmental and local permits that are required as a prerequisite to commence construction. Procurement of OFE starts with project start and is complete for assignment to EPC contractor at NTP.

6.0 Capital Cost Estimate

EPC Contractor

- Estimate Basis, Rev F/H Supplemental

For Locations 1-5, Dual Fuel and for Location 3 Single Fuel:

- Estimate Summary and Details, revision F (no SCR)
- Estimate Summary and Details, revision H (with SCR)

Owner

For Locations 1-5, Dual Fuel and for Location 3 Single Fuel:

- Owner Cost tabulations no SCR
- Owner Cost tabulations with SCR

Fuel consumption and power generation during commissioning and testing (estimated) for the Simple Cycle plant is as follows:

operating hours	1200	hrs		
duration	50	days		
duration	7	weeks		
generation	215,000	MWhrs		
average load	179	MW		
fuel gas	2,000,000	Dth		
fuel oil	540,000	gals		

7.0 Cash Flow

EPC cash flow is based on the project cost excluding the OFE portion paid by Owner prior to assignment but including the OFE portion after assignment. The percentages of OFE costs to be used are identified in the Owners cost tabulations in Section 6.0. There are no monthly charges until NTP and assignment.

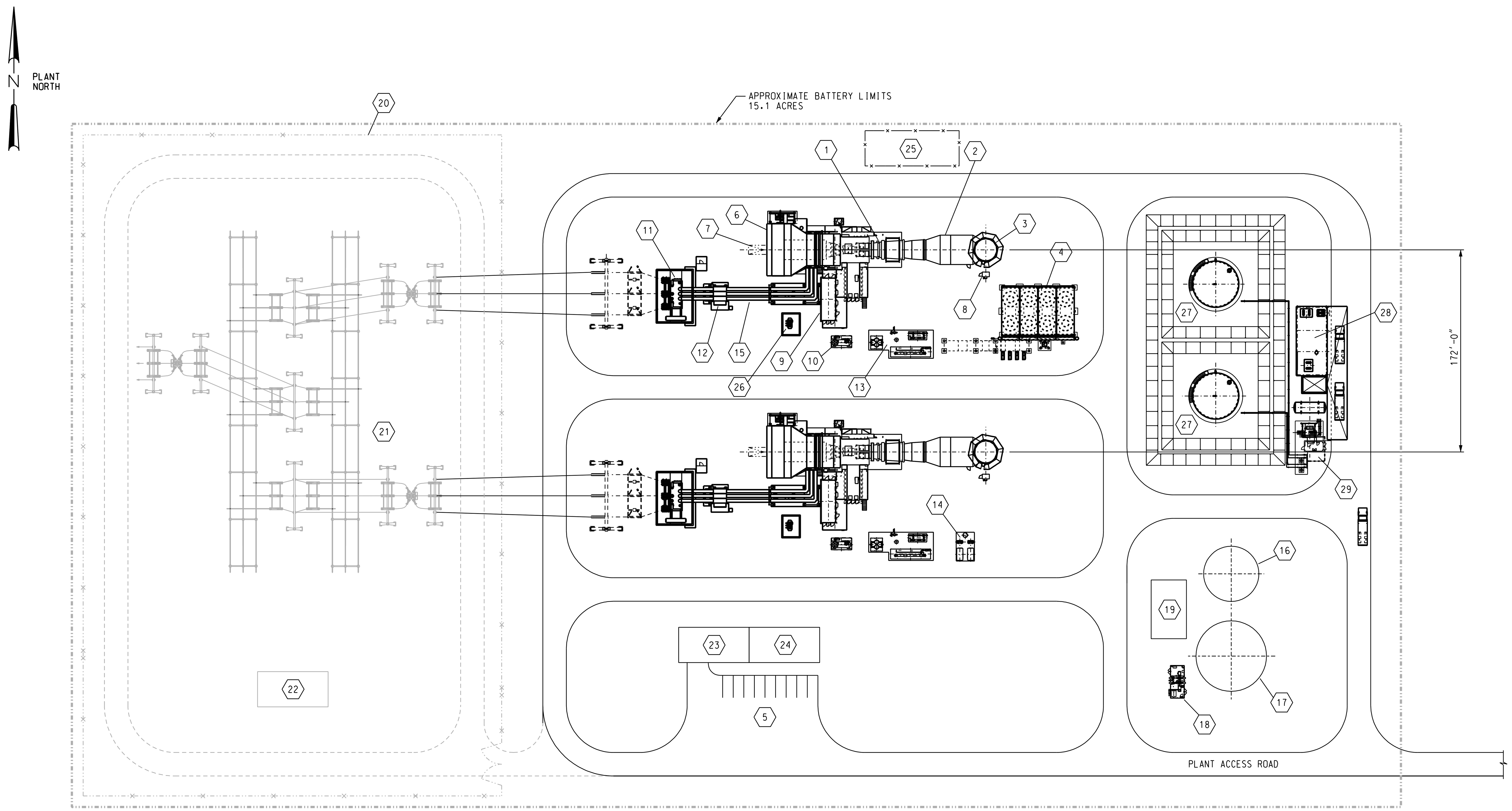
Owner cash flow is based on the OFE portion paid prior to assignment and all sales taxes and runs from project start thru end of project. The percentages of OFE costs to be used are identified in the Owners cost tabulations in Section 6.0. Owner does not make OFE payments after assignment at NTP.

These two percentages cannot be added together to get total monthly cash flows. They have to be converted to cash first, and then added.

- Simple Cycle – Gas Fuel Only Cash Flow, revision F Supplemental (no SCR)
- Simple Cycle – Dual Fuel Cash Flow, revision F Supplemental (no SCR)

- Simple Cycle – Gas Fuel Only Cash Flow, revision H Supplemental (with SCR)
- Simple Cycle – Dual Fuel Cash Flow, revision H Supplemental (with SCR)

APPENDIX A.2. LAYOUT DRAWING FOR DUAL-FUEL CT WITH SCR



EQUIPMENT LEGEND

ITEM	EQPT TAG NO	DESCRIPTION
1		7FA CTG (COMBUSTION TURBINE GENERATOR)
2		TURBINE EXHAUST DUCT
3		EXHAUST STACK
4		FIN FAN COOLER
5		PARKING
6		CTG INLET AIR FILTER
7		CTG ROTOR PULL SPACE
8		CEMS (CONTINUOUS EMISSIONS MONITORING)
9		PEEC
10		CO2 FIRE PROTECTION SYSTEM
11		GSU
12		GENERATOR BREAKER
13		FUEL GAS CONDITIONING SKIDS
14		PLANT/INSTRUMENT AIR COMPRESSORS
15		ISO PHASE BUS
16		DEMINERALIZED WATER STORAGE TANK
17		RAW/FIRE WATER STORAGE TANK
18		FIRE PROTECTION PUMP PACKAGE
19		WATER TREATMENT BUILDING
20		SWITCHYARD FENCE LINE
21		SWITCHYARD
22		SWITCHYARD CONTROL HOUSE
23		WAREHOUSE & MAINTENANCE BUILDING
24		ADMINISTRATION BUILDING & CONTROL ROOM
25		FUEL GAS METERING & REGULATING STATION
26		EXCITATION TRANSFORMER
27		FUEL OIL STORAGE TANKS
28		FUEL OIL UNLOADING & FORWARDING
29		FOAM FIRE PROTECTION SYSTEM
30		-
31		-
32		-
33		-
34		-
35		-
36		-
37		-
38		-
39		-
40		-

60 30 0 60 120
Scale: 1 INCH = 60 FEET

NO.	DATE	REVISION	BY	CHK
P1	06/29/11	ISSUED FOR INTERNAL REVIEW	TBJ	
A	08/23/11	ISSUED FOR FINAL REPORT	TBJ	

RESPONSIBLE ENGINEER
PE #.

REVISION APPROVAL — REV A — DATE 08/23/11

DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL	.	ELECTRICAL	.
STRUCTURAL	.	INST & CNTRL	.
MECHANICAL	.	ARCHITECTURAL	.
PROCESS	.	PLANT LAYOUTS	.
PIPING	.		

STATUS

ISSUED	REV	DATE	DM	SDE	PEM
PRELIMINARY	P1	06/29/11			
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1" = 60'-0"

The Brattle Group
PJM Interconnect Study
Northeast U.S.

PROJECT NO. 421147

CH2MHILL
CH2MHILL Engineers, Inc.

GENERAL ARRANGEMENT
DUAL FUEL
SIMPLE CYCLE
PLOT PLAN

DWG. NO. G-PP-011 REV. A

BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

FILENAME:
PLOT DATE:

APPENDIX A.3. PROJECT SCHEDULE FOR DUAL-FUEL CT WITH SCR

PJM Interconnect Study, Northeast US

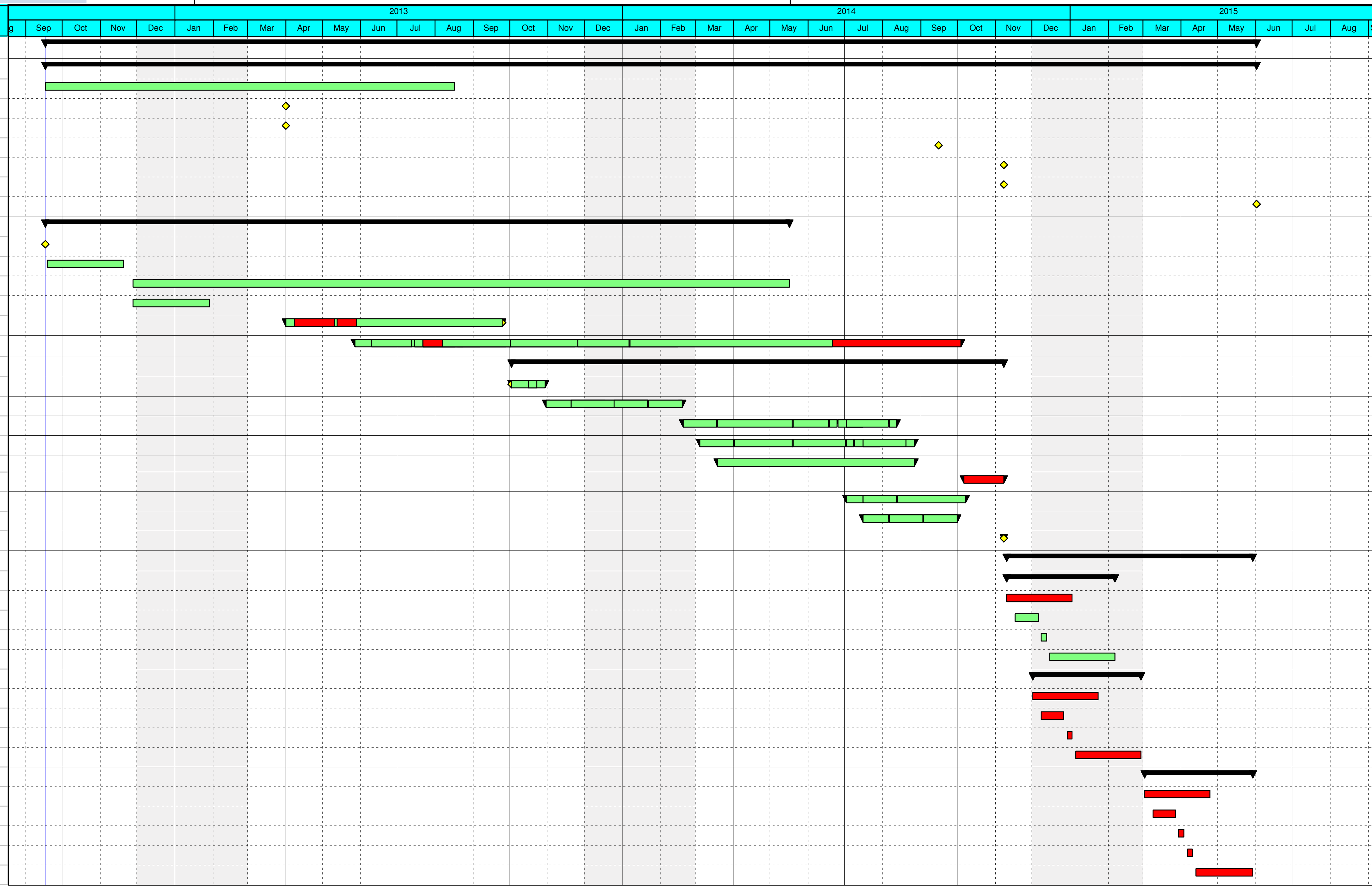
GE 7FA Simple Cycle Plant W/SCR (Dual Fuel)

Project # 421147

The Brattle Group

CH2MHILL

Activity ID	Activity Name	Start	Finish
	PROJECT	17-Sep-12	01-Jun-15
	CONTRACT MILESTONES	17-Sep-12	01-Jun-15
	PERMITTING	17-Sep-12*	16-Aug-13
	NOTICE TO PROCEED	01-Apr-13*	
	ENGINEERING RELEASE	01-Apr-13	
	ELECTRICAL BACKFEED COMPLETE		15-Sep-14
	MECHANICAL COMPLETION		07-Nov-14
	FUEL GAS AVAILABLE		07-Nov-14
	COD		01-Jun-15
	OWNER TASKING	17-Sep-12	16-May-14
	PROJECT START	17-Sep-12	
	SPEC/PROCURE/AWARD CTG's / SCR's	18-Sep-12	19-Nov-12
	FABRICATE & DELIVER CTG'S / SCR's	27-Nov-12	16-May-14
	CRITICAL CTG / SCR DRAWINGS RECIEPT	27-Nov-12	28-Jan-13
	ENGINEERING	01-Apr-13	24-Sep-13
	PROCUREMENT	27-May-13	03-Oct-14
	CONSTRUCTION	02-Oct-13	07-Nov-14
	Sitework	02-Oct-13	29-Oct-13
	U/G Piping & Electrical	30-Oct-13	18-Feb-14
	CTG Unit 1 Erection	19-Feb-14	12-Aug-14
	CTG Unit 2 Erection	05-Mar-14	26-Aug-14
	SCR / Stack Erection	19-Mar-14	26-Aug-14
	GSU Transformers	06-Oct-14	07-Nov-14
	Site Buildings	02-Jul-14	07-Oct-14
	Fuel Oil Facility	16-Jul-14	30-Sep-14
	Initiate Systems Release	07-Nov-14	07-Nov-14
	START UP & COMMISSION	10-Nov-14	29-May-15
	CTG - 1	10-Nov-14	06-Feb-15
	BOP SYSTEMS COMMISSIONING	10-Nov-14	02-Jan-15
	FUNCTIONAL CHECKOUT	17-Nov-14	05-Dec-14
	FIRST FIRE CT-1 (Gas)	08-Dec-14	12-Dec-14
	TUNE & PERFORMANCE/EMISSION TEST	15-Dec-14	06-Feb-15
	CTG - 2	01-Dec-14	27-Feb-15
	BOP SYSTEMS COMMISSIONING	01-Dec-14	23-Jan-15
	FUNCTIONAL CHECKOUT	08-Dec-14	26-Dec-14
	FIRST FIRE CT-2 (Gas)	29-Dec-14	02-Jan-15
	TUNE & PERFORMANCE/EMISSION TEST	05-Jan-15	27-Feb-15
	Fuel Oil Facility	02-Mar-15	29-May-15
	BOP SYSTEMS COMMISSIONING	02-Mar-15	24-Apr-15
	FUNCTIONAL CHECKOUT	09-Mar-15	27-Mar-15
	FIRST FIRE CT-1 (Oil)	30-Mar-15	03-Apr-15
	FIRST FIRE CT-2 (Oil)	06-Apr-15	10-Apr-15
	TUNE & PERFORMANCE/EMISSION TEST	13-Apr-15	29-May-15



Actual Work
Remaining Work
Critical Remaining Work

Level 1 SUMMARY SCHEDULE

APPENDIX A.4. COST DETAIL FOR CT WITH SCR IN CONE AREA 1

Project Name	429 MW 2x0 SC Plant - GE 7241FA.05																**Data Date**					
Client	The Brattle Group									Location 1: Dual Fuel w/ SCR							**Print Date**	**28-Jul-11**		CH2MHILL		
Project Description	Middlesex County, New Jersey																**Rev:**	**H**				
											Total								**%**	**%**	**%**	
				Professional Labor		**Self Perform Craft Labor**		**Subcontract Labor**		**Specialty Sub.**	**Craft**		**Material**		**Const.**	**Specialty**			**Of Direct**	**Of Project**	**Of Project**	
Description	**Quantity**	**UM**	**HRS / UM**	**Hours**	**Labor Amount**	**Hours**	**Labor Amount**	**Hours**	**Labor Amount**	**Hours**	**Hours**	**Eng. Equip**	**Bulk**	**Sub.**	**Equip.**	**Sub**	**Other**	**Total**	**Total**	**Total Revenue**	**Total**	
DIRECT COSTS																						
Concrete	6,062	CY	8.84 MH/CY			53,560h	3,983,765	0h	-	0h	53,560h	-	1,801,676			-		5,785,441	7.3%	4.4%	2.4%	
Steel	103	TN	26.82 MH/TN			2,769h	237,338	0h	-	0h	2,769h	-	304,300			-		541,638	0.7%	0.4%	0.2%	
Piping	26,293	LF	1.68 MH/LF							0h								-	0.0%	0.0%	0.0%	
Above Ground	12,630	LF	2.12 MH/LF			26,806h	2,343,204	0h	-	0h	26,806h		1,224,630					3,567,834	4.5%	2.7%	1.5%	
Below Ground	13,663	LF	1.28 MH/LF			17,430h	1,523,618	0h	-	0h	17,430h		861,843					2,385,461	3.0%	1.8%	1.0%	
Electrical										0h								-	0.0%	0.0%	0.0%	
Wire & Cable	386,246	LF	0.05 MH/LF			20,119h	1,892,460	0h	-	0h	20,119h	838,428	-					2,730,888	3.5%	2.1%	1.1%	
Cable Tray	3,400	LF	0.90 MH/LF			3,060h	287,835	0h	-	0h	3,060h	-	102,000					389,835	0.5%	0.3%	0.2%	
Conduit	78,247	LF	0.14 MH/LF			10,723h	1,008,643	0h	-	0h	10,723h	-	405,292					1,413,935	1.8%	1.1%	0.6%	
Instrumentation	1	LS				9,480h	891,724	0h	-	0h	9,480h	1,374,200	58,004			-		2,323,928	2.9%	1.8%	0.9%	
Heat Tracing	1	LS								1,326h	1,326h					428,550		428,550	0.5%	0.3%	0.2%	
Gas Turbine	1	LS				71,789h	5,590,187	0h	-	0h	71,789h	-	400,000					5,990,187	7.6%	4.6%	2.4%	
Steam Turbine	1	LS				0h	-	0h	-	0h	0h	-	-					-	0.0%	0.0%	0.0%	
HRSG / Boiler / OTSG	1	LS				0h	-	0h	-	0h	0h	-	-					-	0.0%	0.0%	0.0%	
Condenser	1	LS				0h	-	0h	-	0h	0h	-	-					-	0.0%	0.0%	0.0%	
Cooling Tower	1	LS								0h	0h					-		-	0.0%	0.0%	0.0%	
Air Cooled Condenser	1	LS				0h	-	0h	-	0h	0h	-	-			-		-	0.0%	0.0%	0.0%	
GSU Transformers	1	LS				720h	67,726	0h	-	0h	720h	4,680,000	4,000			-		4,751,726	6.0%	3.6%	1.9%	
Mechanical BOP	1	LS				63,894h	4,975,410	0h	-	16,082h	79,976h	4,884,601	51,200			5,197,500		15,108,711	19.1%	11.6%	6.2%	
Electrical BOP	1	LS				16,726h	1,573,300	0h	-	309h	17,035h	4,797,390	231,591			100,000		6,702,280	8.5%	5.1%	2.7%	
Relocation / Demolition Equipment	1	LS								0h						-		-	0.0%	0.0%	0.0%	
Sitework	1	LS				0h	-	7,334h	948,043	4,100h	11,433h	-	23,157			1,324,963		2,296,163	2.9%	1.8%	0.9%	
Buildings & Architectural	1	LS								3,094h	3,094h					1,000,000		1,000,000	1.3%	0.8%	0.4%	
Insulation	1	LS								656h	656h					211,992		211,992	0.3%	0.2%	0.1%	
Painting	1	LS								473h	473h					152,770		152,770	0.2%	0.1%	0.1%	
Fire Protection	1	LS								0h	0h							-	0.0%	0.0%	0.0%	
HVAC / Plumbing	1	LS								0h	0h							-	0.0%	0.0%	0.0%	
Heavy haul	1	LS								1,547h	1,547h					500,000		500,000	0.6%	0.4%	0.2%	
Switchyard	1	LS								0h	0h					-		-	0.0%	0.0%	0.0%	
Premium Time, Shift Differential	1	LS																-	0.0%	0.0%	0.0%	
Bussing	1	LS																-	0.0%	0.0%	0.0%	
Indirect Services & Support	1	LS				5,706h	474,672	0h	-	574h	6,280h		351,764		24,000	185,600		1,036,036	1.3%	0.8%	0.4%	
Temporary Facilities & Services	1	LS				2,126h	176,822	0h	-	7,540h	9,666h		544,961		245,598	2,436,867		3,404,248	4.3%	2.6%	1.4%	
Small Tools & Consumables	1	LS				0h	-	0h	-	0h	0h		1,327,986					1,327,986	1.7%	1.0%	0.5%	
Construction Equip, Operators, Testing,	1	LS				21,421h	1,781,933	0h	-	63h	21,483h		355,631		1,340,858	20,285		3,498,707	4.4%	2.7%	1.4%	
Scaffolding	1	LS				20,000h	1,663,764	0h	-	0h	20,000h							1,663,764	2.1%	1.3%	0.7%	
Startup Craft Labor, Materials, Supplies	1	LS				14,760h	2,095,939	0h	-	2,475h	17,235h		339,000		175,000	800,000		3,409,939	4.3%	2.6%	1.4%	
Freight	1	LS										847,540	333,856					1,181,396	1.5%	0.9%	0.5%	
Export / Import - Warehousing, Loading/Unloading, Warehousing, Customs																		-	0.0%	0.0%	0.0%	
Buy Downs	1	LS																-	0.0%	0.0%	0.0%	
																		-	0.0%	0.0%	0.0%	
Project Indirects (Taxes, Insurances, Bonds, Other)																	7,207,230	7,207,230	9.1%	5.5%	2.9%	7,207,230
																		-	0.0%	0.0%	0.0%	
SUBTOTAL DIRECT COSTS				0h	-	361,088h	**30,568,341**	7,334h	**948,043**	38,240h	406,661h	**17,422,158**	**8,720,892**	-	**1,785,456**	**12,358,525**	**7,207,230**	**79,010,646**	**100.0%**	**60.5%**	**32.2%**	**79,010,646**
			Avg. Rate																			
			/ Hour →↓				$ 84.66		$ 129.27							$ 129.27						

Project Name 429 MW 2x0 SC Plant - GE 7241FA.05
Client The Brattle Group
Project Description Middlesex County, New Jersey

Location 1: Dual Fuel w/ SCR

Data Date
Print Date 28-Jul-11
Rev: H

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				Professional Labor		Self Perform Craft Labor		Subcontract Labor		Specialty Sub.	Total Craft	Material			Const.	Specialty			%	%	%	
Description	**Quantity**	**UM**	**HRS / UM**	**Hours**	**Labor Amount**	**Hours**	**Labor Amount**	**Hours**	**Labor Amount**	**Hours**	**Hours**	**Eng. Equip**	**Bulk**	**Sub.**	**Equip.**	**Sub**	**Other**	**Total**	**Of Direct Total**	**Of Project Total Revenue**	**Of Project Total**	
INDIRECT COSTS																						
PROJECT MANAGEMENT	17,597	HRS																				2,414,780
Home Office Professional (PM/CM)			190.56	3,986h	759,566													759,566	1.0%	0.6%	0.3%	
Project Support Professional (Safe/QC/PC/DocC/Est)			136.29	8,928h	1,216,882													1,216,882	1.5%	0.9%	0.5%	
Clerical			57.90	4,683h	271,127													271,127	0.3%	0.2%	0.1%	
Expenses																	167,205	167,205	0.2%	0.1%	0.1%	
ENGINEERING	30,860	HRS																				3,603,790
Home Office Professional			107.48	29,060h	3,123,317													3,123,317	4.0%	2.4%	1.3%	
Field Professional (Site Support Engineering)			109.71	1,800h	197,473													197,473	0.2%	0.2%	0.1%	
Value Center Engineering																		-	0.0%	0.0%	0.0%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	283,000	283,000	0.4%	0.2%	0.1%	
PROCUREMENT	7,300	HRS																				833,000
Home Office Professional			110.00	7,300h	803,000													803,000	1.0%	0.6%	0.3%	
Field Professional																		-	0.0%	0.0%	0.0%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	30,000	30,000	0.0%	0.0%	0.0%	
SITE MANAGEMENT	82,850	HRS																				8,207,467
Field Professional			110.87	65,314h	7,241,459													7,241,459	9.2%	5.5%	3.0%	
Clerical			33.20	17,537h	582,192													582,192	0.7%	0.4%	0.2%	
Expenses																	383,816	383,816	0.5%	0.3%	0.2%	
STARTUP MANAGEMENT	14,180	HRS																				1,506,266
Home Office Professional			136.50	500h	68,250													68,250	0.1%	0.1%	0.0%	
Field Professional			98.28	13,680h	1,344,516													1,344,516	1.7%	1.0%	0.5%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	93,500	93,500	0.1%	0.1%	0.0%	
SUBTOTAL MANGEMENT COST				152,787h	**15,607,782**	361,088h	**30,568,341**	7,334h	**948,043**	38,240h	406,661h	**17,422,158**	**8,720,892**	**-**	**1,785,456**	**12,358,525**	**8,164,750**	**95,575,948**	**121.0%**	**73.2%**	**39.0%**	**95,575,948**
CONTINGENCY																						Cont. & Escal.
Percentage					5.0%		7.0%		7.0%			13.7%	5.0%		5.0%	6.0%						20,038,730
Dollars					780,389		2,139,784		66,363			2,382,665	436,045		89,273	741,512		6,636,030	8.4%	5.1%	2.7%	
ESCALATION																						
Percentage					12.3%		13.8%		10.3%			19.7%	17.3%		12.9%	15.3%	1.4%					
Dollars					1,915,500		4,211,700		97,600			3,431,400	1,508,500		230,800	1,891,600	115,600	13,402,700	17.0%	10.3%	5.5%	
RISK																		-	0.0%	0.0%	0.0%	
PROJECT SUBTOTAL				152,787h	**18,303,671**	361,088h	**36,919,825**	7,334h	**1,112,006**	38,240h	406,661h	**23,236,223**	**10,665,436**	**-**	**2,105,529**	**14,991,637**	**8,280,350**	**115,614,678**	**146.3%**	**88.6%**	**47.2%**	**115,614,678**

Project Name	429 MW 2x0 SC Plant - GE 7241FA.05		**Data Date**
Client	The Brattle Group	Location 1: Dual Fuel w/ SCR	**Print Date** 28-Jul-11
Project Description	Middlesex County, New Jersey		**Rev:** H

CH2MHILL

Description	Quantity	UM	HRS / UM	Professional Labor Hours	Professional Labor Labor Amount	Self Perform Craft Labor Hours	Self Perform Craft Labor Labor Amount	Subcontract Labor Hours	Subcontract Labor Labor Amount	Specialty Sub. Hours	Total Craft Hours	Material Eng. Equip	Material Bulk	Material Sub.	Const. Equip.	Specialty Sub	Other	Total	% Of Direct Total	% Of Project Total Revenue	% Of Project Total	
																						G&A & Margin
GENERAL OVERHEAD & ADMINISTRATION																						17,286,468
Percentage					0.0%		0.0%		0.0%			0.0%	0.0%		0.0%	0.0%	0.0%					
Dollars					-		-		-			-	-		-	-	-	-	0.0%	0.0%	0.0%	
MARGIN																						
Percentage					10.0%		10.0%		10.0%			10.0%	10.0%		10.0%	10.0%	10.0%					
Dollars					1,830,367		3,691,983		111,201			2,323,622	1,066,544		210,553	1,499,164	828,035	11,561,468	14.6%	8.9%	4.7%	
POWER BLOCK MARGIN																						
Percentage												0.0%										
Dollars												-						-	0.0%	0.0%	0.0%	
Assignment Fee For Owner Supplied Equipment																			0.0%	0.0%	0.0%	
Percentage												5.0%										
Dollars												5,725,000						5,725,000	7.2%	4.4%	2.3%	
PROJECT COST W/MARKUPS				152,787h	**20,134,038**	361,088h	**40,611,808**	7,334h	**1,223,207**	38,240h	406,661h	**31,284,845**	**11,731,980**	**-**	**2,316,082**	**16,490,801**	**9,108,385**	**132,901,145**	**168.2%**	**101.8%**	**54.2%**	**132,901,145**
Sales Tax Deduction																		(2,349,072)	-3.0%	-1.8%	-1.0%	(2,349,072)
Management Adjustments																		-	0.0%	0.0%	0.0%	
PROJECT TOTAL REVENUE				152,787h	**20,134,038**	361,088h	**40,611,808**	7,334h	**1,223,207**	38,240h	406,661h	**31,284,845**	**11,731,980**	**-**	**2,316,082**	**16,490,801**	**9,108,385**	**130,552,074**	**165.2%**	**100.0%**	**53.3%**	**130,552,074**
OWNER FURNISHED EQUIPMENT																		-	0.0%		0.0%	
CTGs												93,000,000						93,000,000	117.7%		38.0%	
HOT SCRs												21,500,000						21,500,000	27.2%		8.8%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
																		-	0.0%		0.0%	
																		-	0.0%		0.0%	-
																		-	0.0%		0.0%	
																		-	0.0%		0.0%	
PROJECT TOTAL				152,787h	**20,134,038**	361,088h	**40,611,808**	7,334h	**1,223,207**	38,240h	406,661h	**145,784,845**	**11,731,980**	**-**	**2,316,082**	**16,490,801**	**9,108,385**	**245,052,074**	**310.2%**	**100.0%**	**100.0%**	**130,552,074**

245,052,000

APPENDIX A.5. CASH FLOW SCHEDULE FOR CT WITH SCR IN CONE AREA 1

The Brattle Group

429 MW 2x0 SC Plant - GE 7241FA.05

EPC Cashflow

	08/15/11	**Rev**	**H**
	Dual Fuel: w/ SCR		**CUMULATIVE**
MONTH		**%**	**%**
1	**Sep-12**	0.000%	0.000%
2	**Oct-12**	0.000%	0.000%
3	**Nov-12**	0.000%	0.000%
4	**Dec-12**	0.000%	0.000%
5	**Jan-13**	0.000%	0.000%
6	**Feb-13**	0.000%	0.000%
7	**Mar-13**	0.000%	0.000%
8	**Apr-13**	4.920%	4.920%
9	**May-13**	2.419%	7.338%
10	**Jun-13**	2.691%	10.029%
11	**Jul-13**	2.863%	12.892%
12	**Aug-13**	2.790%	15.682%
13	**Sep-13**	2.572%	18.254%
14	**Oct-13**	4.619%	22.873%
15	**Nov-13**	3.200%	26.073%
16	**Dec-13**	5.383%	31.456%
17	**Jan-14**	3.846%	35.302%
18	**Feb-14**	5.933%	41.235%
19	**Mar-14**	3.936%	45.171%
20	**Apr-14**	12.460%	57.630%
21	**May-14**	3.404%	61.034%
22	**Jun-14**	3.070%	64.104%
23	**Jul-14**	4.088%	68.192%
24	**Aug-14**	3.708%	71.901%
25	**Sep-14**	4.499%	76.399%
26	**Oct-14**	4.568%	80.967%
27	**Nov-14**	3.422%	84.389%
28	**Dec-14**	4.060%	88.449%
29	**Jan-15**	2.800%	91.249%
30	**Feb-15**	2.275%	93.524%
31	**Mar-15**	1.367%	94.891%
32	**Apr-15**	1.391%	96.282%
33	**May-15**	0.866%	97.148%
34	**Jun-15**	2.852%	100.000%

The Brattle Group

429 MW 2x0 SC Plant - GE 7241FA.05

Owner Cash Flow

08/15/11	**Rev**	**H**
Dual Fuel: w/ SCR	**Monthly**	**CUMULATIVE**
MONTH	**%**	**%**
1	0.00%	0.00%
2	0.00%	0.00%
3	34.78%	34.78%
4	0.00%	34.78%
5	17.39%	52.17%
6	0.00%	52.17%
7	0.00%	52.17%
8	1.17%	53.33%
9	1.20%	54.54%
10	1.23%	55.77%
11	1.26%	57.03%
12	1.29%	58.32%
13	17.41%	75.73%
14	2.39%	78.12%
15	1.38%	79.51%
16	2.52%	82.03%
17	1.45%	83.48%
18	2.52%	86.00%
19	1.64%	87.64%
20	5.59%	93.23%
21	1.13%	94.36%
22	0.49%	94.85%
23	0.57%	95.41%
24	0.62%	96.04%
25	0.46%	96.50%
26	0.54%	97.04%
27	0.43%	97.47%
28	0.35%	97.82%
29	0.30%	98.12%
30	0.20%	98.32%
31	0.20%	98.53%
32	0.16%	98.69%
33	0.11%	98.80%
34	1.20%	100.00%

APPENDIX B. CH2M HILL COMBINED-CYCLE COST ESTIMATES

CH2M HILL's detailed engineering cost estimates for plant proper costs including both EPC contractor costs and owner-furnished equipment costs are contained in this appendix for each combined-cycle plant configuration examined. A summary report describing detailed plant specifications and summary cost results for each CC configuration in each CONE Area is contained in CH2M HILL's summary report in Appendix B.1. Plant layout drawings, project schedules, cost estimate details, and cash flow schedules were also provided for each CC location and configuration. Appendices C.2 through C.5 contain this detailed supporting information for one of the CONE Area 1 plant configuration, which is a dual-fuel plant.

APPENDIX B.1. COMBINED-CYCLE PLANT PROPER COST ESTIMATE REPORT

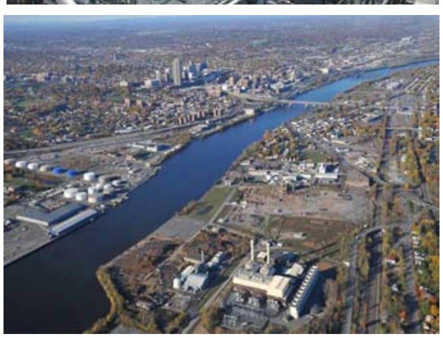
APPENDIX B.2. LAYOUT DRAWING FOR DUAL-FUEL CC

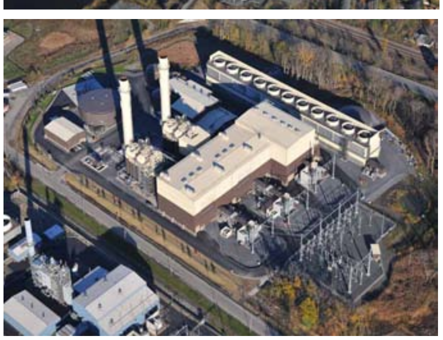
APPENDIX B.3. PROJECT SCHEDULE FOR DUAL-FUEL CC

APPENDIX B.4. COST DETAIL FOR CC IN CONE AREA 1

APPENDIX B.5. CASH FLOW SCHEDULE FOR CC IN CONE AREA 1

APPENDIX B.1. COMBINED-CYCLE PLANT PROPER COST ESTIMATE REPORT





Combined Cycle Cost Estimate
2 x 1 GE 7FA Reference Plant

Brattle Group
PJM Estimating Support

Prepared By CH2M HILL
Project No. 421147
Rev. C
August 2011

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2.0 Development Approach 4
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Revision	Description	Date
A	Issued for Review	July 1, 2011
B	Comments Incorporated	August 2, 2011
C	Final	August 23, 2011

1.0 Executive Summary

CH2M HILL Engineers, Inc. was engaged by the Brattle Group, Inc to provide capital cost estimates for gas fuel only and dual fuel (oil & natural gas) GE 7FA.05 gas turbine combined cycle power plants at multiple sites, each capable of generating approximately 701 MW. The plant configurations each consist of two (2) GE Frame 7FA.05 combustion turbine generators (CTGs), two (2) duct fired three pressure reheat Heat Recovery Steam Generators (HRSGs), one (1) condensing reheat Steam Turbine Generator (STG), surface condenser and all necessary Balance of Plant (BOP) equipment.

Dual Fuel Combustion Turbines

As a basis for the dual fuel combustion turbine estimates CH2M HILL developed the following information:

- Capital costs for five (5) geographical areas (New Jersey, Maryland, Illinois, Pennsylvania, and Virginia)
- A General Arrangement drawing for a representative combined cycle power plant
- A Level One Project schedule
- A basic monthly cash flow tabulation

The capital cost estimates for each geographical area are summarized in the table below. The details of the cost breakdown for each location are included in Section 6.0.

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
New Jersey	Union	356,186,888	194,785,565	547,444,257
Maryland	Non-Union	274,566,035	192,061,631	466,627,666
Illinois	Union	348,377,452	194,784,480	543,161,932
Pennsylvania	Union	333,447,565	192,106,147	525,553,712
Virginia	Non-Union	274,373,867	189,384,692	463,758,559

Gas Fuel Only Combustion Turbines

As a basis for the gas fuel only combustion turbine estimate CH2M HILL developed the following information:

- Capital cost for the Will County, Illinois location
- A General Arrangement drawing for a representative simple cycle power plant
- A Level One Project schedule
- A basic monthly cash flow tabulation

The capital cost estimate for the natural gas fuel combustion turbine for Will County, Illinois is summarized in the table below. The details of the cost breakdown for this location are included in Section 6.

Geographical Area	Labor Type	EPC Costs $	Owner Costs $	Total Installed Capital Cost - $
Illinois	Union	334,931,825	191,257,369	526,189,194

2.0 Development Approach

2.1 Estimating Process

For the development of the capital cost estimate, CH2M HILL utilized our Power Plant Indicative Cost Estimating Methodology which is based upon the plant specific configuration, location specific productivity and labor cost factors, and our extensive current cost data base for equipment and material. These factors are processed using our proprietary Indicative Estimating Software Model to produce a detailed analysis of the cost elements for the project that are then compared to recently completed similar projects.

Project Configurations

CH2M HILL's experience with various plant configurations is extensive. The combustion turbines shown in the table below have been designed and installed in combined cycle, simple cycle and cogeneration modes.

- 1 X LMS 100 simple cycle
- 2 X F-class simple cycle
- 4 X LM 6000 simple cycle
- 12 X FT-8 Twin Pack simple cycle
- 1 X 1 F-class combined cycle
- 2 X 1 F-class combined cycle
- 3 X 1 E-class combined cycle

CH2M HILL's estimating team retains standard plant layout configurations that have been imported into the estimating data base for use in this study. The design basis for this study is a 2 x 1 - 7F class combined cycle, the details for which are defined in Sections 3.0 – Plant Scope and Section 4.0 – General Arrangement of this report.

Variability by Location

The US construction industry has the most variability in productivity and execution strategy by location than any other country in the world. Project execution ranges from strong union locations such as New York City, Chicago, San Francisco and St. Louis to lower cost, merit shop locations such as the Gulf Coast and Southeast US. CH2M HILL's historical database tracks and updates labor productivity by location. CH2M HILL's "base" productivity location is the Gulf Coast, like many national contractors. At that location, the base productivity for each discipline trade is considered a 1.0 productivity factor and is considered the most efficient location to perform work based on worker skills and efficiency. That 1.0 productivity factor is then adjusted to reflect union labor, local labor rules and other historical data.

Variability of Estimates for Material and Equipment

Certain material and equipment costs are more volatile in the heavy industrial market than others. As examples, high temperature- high pressure pipe, electrical transformers and copper wire are high in demand in the oil & gas market as well as the power market. When both industries are busy, costs increase dramatically due to not only material and manufacturing costs, but also due to greater demand than supply. Market conditions sometimes make it nearly impossible to assess with any certainty the proper amount of escalation to apply to some materials and equipment. This is compounded by the extended time from estimate development to project implementation. CH2M HILL's constant activity in bidding and procuring material and equipment provides more accurate costs that reflect current market conditions than available by other means.

CH2M HILL's Indicative Estimating Software Model

CH2M HILL has taken over 20 years of data from our involvement in the Power industry and developed an indicative database to aid in estimating future projects. The "Power Indicative Estimating Program" derives project costs based on information that is input on various worksheets within the program from a series of inputs, multiple logic functions and iterations, and a preliminary Indicative Estimate is produced which can be reviewed and modified as necessary.

Power Indicative Estimating Program Output

Once a project configuration, location, schedule and execution model is defined, the indicative estimator works with a Power Project Engineer to reflect other project properties unique to the project. The estimator inputs the specific project data into the model and then reviews with experienced construction managers and engineers to confirm alignment.
The program produces an estimating basis and a series of outputs. Some of these outputs include:

- Quantities of concrete, structural steel, pipe, conduit, cable and insulation
- Equipment required by system
- Work-hours for labor by discipline
- Engineering hours
- Construction supervision hours
- Startup and testing hours
- Indirect labor and equipment

The program allows the estimator to input the latest labor rates, productivity, which is then tabulated in the program to develop the final cost of the plant. The results of these analyses are contained in Section 6.0 of this report.

2.2 Owner Cost Estimates

Pricing for the three major components, the Combustion Turbine Generators (CTGs), the Heat Recovery Steam Generators (HRSGs) and the Steam Turbine Generator (STG), is based on GE Power Island information obtained from similar plants CH2M HILL has constructed and proposed. Note that GE's scope includes the Continuous Emissions Monitoring Systems(CEMS), Packaged Electrical and Electronic Control Cabs (PEECC), the Plant Distributed Control System (DCS) and the CTGs and STG auxiliary equipment.

These components (Owner Furnished Equipment or OFE) are procured by the Owner at project start, prior to EPC contract NTP. They are assigned to the EPC contractor at that time. Estimates of Owner costs that are in addition to the EPC contract cost are tabulated in Section 6.0.

2.3 EPC Cost Estimate

Pricing for the major Balance of Plant equipment including the ST surface condenser, cooling tower and generator step-up transformers were obtained from actual pricing and budgetary quotes received from vendors for similar recent projects and proposals.

The plant construction cost estimates were developed based on data from recent EPC projects. Labor rates and productivity factors for the following five (5) geographical areas were verified and used to develop the direct and indirect costs.

- 1) Middlesex County, New Jersey
- 2) Charles County, Maryland
- 3) Will County, Illinois
- 4) Northampton County, Pennsylvania
- 5) Fauquier County, Virginia

The construction cost estimates are based on direct labor hire (concrete, steel, piping, electrical and instrumentation) and specialty subcontract union (locations 1, 3, and 4) and merit shop craft labor (locations 2 and 5). Quantities for bulks were determined from plants similar in size and configuration. Historical data was utilized to provide an overall parametric check of account values of the completed estimate.

Labor

<u>Locations 1, 3, and 4</u>: Union craft labor rates were determined from prevailing wages for the area. Rates were built-up including the base rate, fringes and legalities. The estimate is based on a 50 hour craft work week. A labor factor of 1.1 was applied to the CSA accounts, 1.3 for the piping accounts, and 1.2 on all other accounts and based on various factors including location, working in an existing facility, congestion, local labor conditions, weather and schedule.

<u>Locations 2 and 5:</u> Merit shop craft labor rates were determined from prevailing wages for the area. Rates were built-up including the base rate, fringes and legalities. The estimate is based on a 50 hour craft work week. A labor factor of 1.0 was applied to all accounts based on various factors. A $50 per day per diem has been included.

Escalation

The cost estimates are provided in June 2011 dollars and escalation was included based on the following schedules.

- Craft labor was escalated at 4.0% for 2011 and beyond.

- Engineered equipment and bulk materials were escalated at 6% for 2011 and beyond. Professional labor and construction indirect expenses were escalated at 3% for 2011 and 4% for 2012 and beyond.
- Specialty subcontracts were escalated at 5% for 2011 and beyond.

Contingency & Gross Margin

Contingency was included at:

- 5% for Professional Labor, Material and Construction Equipment
- 7% for Craft Labor
- 6% for Specialty Subcontracts
- 2% for the CTGs and STG
- 3% for the HRSGs
- 3% for Engineered Equipment

A gross margin of 10% was applied with 5% assignment fee applied to the Owner Furnished Equipment.

Project Indirects

Project indirects include:

- Builders Risk insurance
- General and excess liability insurance
- Performance and payment bonds
- Construction permits
- Sales tax (not including OFE) to roll up through markups then taken out at bottom line
- Letter of credit in lieu of retention
- Warranty
- Bonus pool

Scope - Inclusions

- Structural and civil works
- Mechanical, electrical, and control equipment
- Electrical Power Distribution Center (pre-assembled & tested)
- Heavy haul (allowance)
- Operator training
- O&M manuals
- Escalation
- Bulks including piping and instrumentation
- Contractor's construction supervision
- Temporary facilities
- Construction equipment, small tools and consumables

- Start-up spare parts and start-up craft labor
- Construction permits allowance ($100,000)
- First fills
- Insurances
- Gross margin
- 5% Letter of Credit in lieu of retention
- Construction power, water and natural gas consumption
- Performance and Payment Bond
- Builders All Risk Insurance (costs broken out from EPC estimate for reference – see Estimate Basis Section 17.0)

Scope - Exclusions

- Soils remediation, moving of underground appurtenances or piping
- Dewatering except for runoff during construction
- Wetland mitigation
- Fuel gas compression
- Noise mitigation measures or study (unless otherwise noted)
- Piling
- Geotechnical investigation and survey (shown separately from EPC estimate as an Owners cost)
- Sales Tax (shown separately from EPC estimates as an Owners cost)
- Permitting/Environmental permits (shown separately from EPC estimates as an Owners cost)
- Fuel oil and natural gas consumption during startup (shown separately from EPC estimate as an Owners cost)
- Switchyard

Scope - Assumptions & Clarifications

- Assumes flat, level and cleared site.
- Assumes free and clear access to work areas.
- This site does not contain any EPA defined hazardous or toxic wastes or any archeological finds that would interrupt or delay the project.
- Spread footings are assumed for all equipment.
- All excavated material is suitable for backfill/compaction.
- Rock excavation is not required.
- Temporary power and water will be available at site boundary as required to support construction at no cost to Contractor.
- An ample supply of skilled craft is available to the site.
- TA services are owner provided as part of their equipment supply.
- Craft bussing is not required.
- Ample space (provided by owner) for craft parking, temporary facilities, laydown and storage is available adjacent to site.
- Field Erected Storage Tanks are carbon steel with internal high build epoxy coatings.

- Access road modifications and improvements (beyond the site boundary battery limit) will be performed by others.
- Roads for heavy haul are suitable for transportation and contain no obstructions for delivery of heavy/oversized equipment.
- Heavy haul is assumed to be from a rail siding within one mile of the plant to setting on foundations.
- Equipment is supplied with manufacturer's standard finish paint.
- Natural gas is delivered at an adequate pressure and no gas compression is required
- Gas metering station is by others
- The electrical equipment and water treatment equipment will be housed in pre-fabricated building
- The electrical scope concludes at the high side of the Generator Step-up (GSU) transformers. Transmission line and substation costs are by others.
- Heat tracing has not been included for large above ground process piping where system pumps can be operated to prevent freezing, or where the system can be drained during extended cold weather outages.

3.0 Plant Scope

3.1 General Description

The proposed combined cycle power plant has a nominal generating capacity of approximately 701 MW at 59 °F outdoor ambient temperature when operating on gas fuel. The major components of the project include two (2) GE Frame 7FA.05 Combustion Turbine Generators (CTGs) each with a dedicated reheat Heat Recovery Steam Generator (HRSG), one (1) shared reheat Steam Turbine Generator (STG), surface condenser, cooling tower, air pollution controls and associated auxiliary and control systems. The CTGs will be equipped with inlet evaporative coolers to increase power output at high ambient temperature. The HRSGs will generate steam at three pressure levels and will be equipped with natural gas fired duct burners to provide additional steam to augment power output. The plant (dual fuel CT option) will operate both on natural gas and distillate fuel oil. The CTGs will be equipped with dry-low NOx combustors (gas fuel operation) and the HRSGs with Selective Catalytic Reduction (SCR) control systems to reduce NOx emissions. The HRSGs will also be equipped with oxidation catalyst systems to reduce CO and VOC emissions. The CTGs will be equipped with water injection for NOx control when operating on distillate fuel (dual fuel option).

The termination points for the power facility are at the battery limits of the facility and include the following:

- High Pressure natural gas supply downstream of the gas metering station (by others) at the power facility boundary
- Water from the municipal water supply at the power facility boundary
- Waste to the municipal sewer at the power facility boundary
- Electrical connection is at the high side of the generator step-up transformers

The facility is assumed to be located on a Greenfield site. There will be three buildings included in the plant layout: an integrated administration/control room/warehouse/maintenance building, an electrical/water treatment building, and a STG building. Buildings are of pre-fabricated construction with the exception of the STG building. Layout of the plant shall be in accordance with the General Arrangement drawing included in Section 4.0.

General performance parameters are tabulated below for the (2x1) combined cycle plant. Predicted emissions data is also provided based on generic data for CTG and SCR performance using estimated stack emissions concentrations and rates.

	GAS			
	Evaporative Cooling			
Plant configuration	2x1	2x1	2x1	2x1
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Duct Burner Status	OFF	ON	OFF	ON
Fuel Heating Value, Btu/Lb (LHV)	21,515	21,515	21,515	21,515

CT Generators terminal power, kW	426,560	426,560	397,978	397,978
ST Generator terminal power, kW	223,440	300,120	207,320	281,440
Gross Plant Power, kW	650,000	726,680	605,298	679,418
Gas Turbine Fuel Input, Btu/Hr	3,805,768,320	3,805,768,320	3,628,763,400	3,628,763,400
Duct Burner Fuel Input, Btu/Hr	0	570,000,000	0	570,000,000
Total Fuel Input, Btu/Hr	3,805,768,320	4,375,768,320	3,628,763,400	4,198,763,400
Gross Plant Heat Rate, Btu/kWH (LHV)	5,855	6,022	5,995	6,180
Plant Auxiliary Loads, kW	22,750	25,434	21,185	23,780
Net Plant Power, kW	627,250	701,246	584,113	655,638
Net Plant Heat Rate, Btu/kWH (LHV)	6,067	6,240	6,212	6,404

	FUEL OIL			
	Evaporative Cooling			
Plant configuration	2x1	2x1	2x1	2x1
CTG Load Point	100%	100%	100%	100%
Ambient Temperature, oF	59	59	92	92
Relative Humidity, %	60	60	53	53
Evaporative Cooling	ON	ON	ON	ON
Duct Burner Status	OFF	ON	OFF	ON
Fuel Heating Value, Btu/Lb (LHV)	18,300	18,300	18,300	18,300

CT Generators terminal power, kW	437,560	437,560	423,734	423,734
ST Generator terminal power, kW	221,300	289,240	210,530	275,180
Gross Plant Power, kW	658,860	726,800	634,264	698,914
Gas Turbine Fuel Input, Btu/Hr	4,205,466,000	4,205,466,000	4,116,575,810	4,116,575,810
Duct Burner Fuel Input, Btu/Hr	0	460,000,000	0	460,000,000
Total Fuel Input, Btu/Hr	4,205,466,000	4,665,466,000	4,116,575,810	4,576,575,810
Gross Plant Heat Rate, Btu/kWH (LHV)	6,383	6,419	6,490	6,548
Plant Auxiliary Loads, kW	23,060	25,438	22,199	24,462
Net Plant Power, kW	635,800	701,362	612,065	674,452
Net Plant Heat Rate, Btu/kWH (LHV)	6,614	6,652	6,726	6,786

GE 7FA.05						
OPERATING CONDITION		**N. Gas**	**Fuel Oil**			
Ambient DBT Deg F		59	59			
Relative Humidity %		60	60			
Gas Turbine Unit Exhaust						
Flow Rate	lbs/hr	4,132,000	4,151,000			
Temperature	deg F	1113	1147			
Argon	% VOL	0.88	0.84			
Nitrogen	% VOL	74.18	70.7			
Oxygen	% VOL	12.26	10.68			
Carbon Dioxide	% VOL	3.85	5.74			
Water	% VOL	8.83	12.04			
Gas turbine Emissions						
NOx corrected to 15% O2	ppmvd	9	42			
NOx as NO2	lbs/hr	69	370			
CO corrected to 15% O2	ppmvd	9	20			
CO	lbs/hr	33	72			
UHC	ppmvd	7	7			
UHC	lbs/hr	16	16			
PM10 particulates	lbs/hr	9	17			

After HRSG/SCR

	Gas CC	
	N.G (ppmvd)	F.O. (ppmvd)
NO_x	2	5
VOC	5	5
CO	5	11
$PM_{2.5}$	--	--
SO_2	Note A	Note B

	Gas CC	
	N.G (lb/hr)	F.O. (lb/hr)
NO_x	15.6	44.5
VOC	13.5	15.5
CO	23.7	59.5
$PM_{2.5}$	9	17
SO_2	5.4	6.9

	Gas CC	
	N.G (lb/MMBtu)	F.O. (lb/MMBtu)
NO_x	4.10E-03	1.06E-02
VOC	3.55E-03	3.69E-03
CO	6.23E-03	1.41E-02
$PM_{2.5}$	2.36E-03	4.04E-03
SO_2	1.43E-03	1.64E-03

	Gas CC 2X1	
	Natural Gas	Fuel oil
Heat input (MMBtu/hr)	3,806	4,205
Fuel Heating Value Btu/Lb (LHV)	21,515	18,300

Notes
A - 0.5 grains/100 scf
B - 15 ppm on a mass basis for fuel oil
c - Assumed heating value of natural gas of 1000 Btu/scf

3.2 Owner Furnished Equipment (OFE)

The following paragraphs describe the equipment for which the Owner is responsible to procure.

Combustion Turbine Generators (Power Island Scope) - The combustion turbine generators (CTG's) operate to produce electrical power and waste heat. The plant will include two (2) General Electric 7FA.05 combustion turbine-generators packaged for outdoor installation. Depending upon the site the combustion turbines will be equipped for gas fuel only operation or dual fuel (distillate fuel & natural gas) fuel operation. Units equipped for distillate fuel operation will require a water injection system for NOx emissions control. The CTG equipment package includes the following accessory systems:

- DLN Combustion System (Natural Gas and Distillate fuel oil)
- Water Injection System (for distillate fuel operation)
- Lube Oil System
- Hydraulic Control Oil Systems
- Water Wash System
- Exhaust System
- Inlet Air Filtration System (with noise abatement)
- Inlet Air Cooling System (evaporative)
- Starting System (with turning gear)
- Dual Fuel Control Systems (gas and distillate fuels)
- Variable Inlet Guide Vane (IGV) System
- Mark VI (TMR) Turbine Control & Protection System

Distributed Control System (Power Island Scope) - The Distributed Control System (DCS) will be a GE MARK VI Triple Modular Redundant (TMR) control system provided by GE as part of the power island package. The DCS shall provide for the supervisory control of the Combustion Turbine Generators and Steam Turbine Generator. In addition the DCS shall provide for the control and protection of the HRSGs and all Balance of Plant (BOP) equipment, excepting those systems that are better suited for local control such as the Water Treatment System, Instrument Air Dryers, CEMs, BMS and miscellaneous sumps. Where local controls are used, common trouble alarms and supervisory control functions shall be provided by the DCS. Human Machine Interfaces (HMIs) shall be located in the Central Control Room and locally at each major piece of equipment.

Continuous Emissions Monitoring System (Power Island Scope) - A fully certified Continuous Emissions Monitoring System (CEMS) shall be provided (by GE) for each CTG to continuously monitor the emissions from each CTG and HRSG duct burner. A Data Acquisition and Handling System (DAHS) shall be provided capable of logging and reporting emissions as required by the Air Quality Permit. The equipment shall be housed in a temperature and humidity controlled CEMS shelter.

Heat Recovery Steam Generator (Power Island Scope) - The Heat Recovery Steam Generators (HRSG) function to generate high-quality, superheated steam utilizing exhaust heat from the combustion turbine. Steam is generated at three (3) pressure levels for admission into the steam turbine. One HRSG will be supplied for each CTG as part of the Power Island purchase. The major components of each HRSG are as follows:

- Ductwork from combustion turbine
- Three pressure drums
- Low Pressure (LP) Economizer
- Low Pressure (LP) Evaporator
- Low Pressure (LP) Superheater
- Intermediate Pressure (IP) Economizer
- Intermediate Pressure (IP) Evaporator
- Intermediate Pressure (IP) Superheater
- High Pressure (HP) Evaporator
- High Pressure (HP) Economizer
- High Pressure (HP) Superheater
- High Pressure Reheater
- Main Steam Attemporator
- Reheat Steam Attemporator
- Natural Gas fired duct burner
- Ductwork to stack
- 150 foot high, 18'6" diameter stack
- SCR system utilizing 19% aqueous ammonia
- CO Catalyst
- N2 blanket connections

<u>Steam Turbine Generator (Power Island Scope)</u> - A single steam turbine generator produces electrical power from steam produced by the two (2) HRSGs. This steam turbine is a multistage, reheat, condensing type turbine. The turbine will have a downward exhaust with an expansion joint between the condenser and turbine. The major components include:

- Turbine Sections – HP, IP and LP
- Generator
- Stop/Control Valves
- Reheat Intercept/Stop Valves
- High Pressure Control Oil System
- Lube Oil System
- Steam seal and exhauster system
- Turning Gear
- Mark VI (TMR) Turbine Control System

3.3 EPC Scope

The following paragraphs describe the equipment for which the EPC contractor shall be responsible for procurement.

3.3.1 Gas Fuel Only – Combustion Turbines

Ammonia System - The aqueous ammonia system stores and delivers ammonia to the HRSG's Selective Catalytic Reduction (SCR) system for the reduction of NOx emissions. The major equipment consists of the following:

- Two (2) 100% ammonia forwarding pumps
- One (1) nominal 20,000 gallon horizontal storage tank
- One (1) evaporator
- Tank truck unloading area

Auxiliary Steam Boiler - The auxiliary steam boiler is used to maintain the steam turbine shell and rotor metal temperatures hot during shutdown and to provide sealing steam to the steam turbine to enable more rapid startups. The major equipment consists of the following:

- One (1) 77,000 lb/hr Packaged Auxiliary Boiler
- Stack
- Deaerator
- Two (2) 100% capacity boiler feedpumps
- Instruments, valves and controls

Auxiliary Cooling Water System - The auxiliary cooling water system is a closed loop cooling water system supplying cooling water to the gas turbine generator coolers, steam turbine & gas turbine lube oil coolers and other auxiliary equipment. The major equipment includes the following:

- Two (2) 100% Pumps
- Two (2) 100% Plate and Frame Heat Exchangers
- Surge Tank
- Chemical Addition Tank

Auxiliary Electrical System - The auxiliary electrical system provides a means of stepping-down the generator terminal voltage to deliver power to the plant auxiliaries at a reduced voltage. Typical major equipment includes:

- Auxiliary cable and/or bus
- Station unit auxiliary transformers (UAT)
- 5 kV switchgear
- 5kV medium voltage motor controller gear (MVMC)
- Station service transformers (SST)
- secondary unit substations (SUS)
- 480 V motor control centers (MCC)

Boiler Blowdown System - The boiler blowdown system collects the blowdown streams from the HRSGs and directs them to the blowdown tank for draining to plant drains. Additionally, startup blowdown, blow-offs, and other high temperature drains can be collected in the blowdown tank. The service water cools the streams prior to flowing to the plant drains. The major equipment includes one (1) blowdown tank per HRSG provided with the power island equipment supplied (by GE).

<u>Circulating Water System</u> - The plant circulating water system provides cooling water for the condenser and for auxiliary cooling system. Makeup water for the circulating water system is provided by the city and blowdown is sent to the municipal sewer system. The major equipment includes:

- Two (2) 50% circulating water pumps
- Multiple cell, mechanical draft cooling tower with pump basin
- Tower basin screens
- Level control valves
- Piping, valves and instrumentation

<u>Condensate System</u> - The condensate system receives turbine exhaust steam, turbine bypass steam and other miscellaneous steam drains then transports condensate from the hot well to the low-pressure drum of the HRSG for de-aeration. The condenser also provides a storage volume for other plant steam drains and the low-pressure, intermediate-pressure and high-pressure (cascading) steam turbine bypasses. The bypasses shall be designed for the steam turbine rapid startup and shutdown requirements. The major equipment includes the following:

- Three (3) 50% capacity Condensate Pumps with Motor Drives
- Steam Condenser
- Gland Seal Condenser (provided with STG)
- Two (2) 100% capacity liquid ring mechanical vacuum pumps
- Control Valves and Instrumentation

<u>Chemical Feed System</u> - The purpose of the chemical feed system is to protect the HRSG from corrosion and scale formation, and to provide protection of the circulating water from scaling, bio-fouling and controlling pH. The major equipment includes:

- HRSG - Two (2) phosphate chemical feed skids each with one (1) 100% HP & one (1) 100% IP injection pumps, day tank if required, piped, prewired and including necessary components and accessories for a complete functional feed skid.

- HRSG - Two (2) feed water chemical feed skids each with two (2) 100% injection pumps (oxygen scavenger & amine), day tanks if required, piped, prewired and including necessary components and accessories for a complete functional feed skid.

- Circulating Water - One (1) acid chemical feed skid with two (2) 100% injection pumps, day tank, piped, pre-wired and including necessary components and accessories for a complete functional feed skid.

- Circulating Water - One (1) biocide chemical feed skid with two (2) 100% injection pumps, piped, prewired and including necessary components and accessories for a complete functional feed skid.

Cathodic Protection System – The cathodic protection system function to mitigate galvanic action and prevent corrosion on the underground natural gas piping. The major equipment includes:

- Sacrificial anodes
- Cable
- Test boxes for potential measurement
- Insulating flanges.

DC Power System - The DC power system functions to provide a reliable source of motive and control power for critical equipment, the emergency shutdown of the plant, and the egress of plant personnel during blackout conditions. These loads typically include control power for power circuit breakers, switchgear, protective relaying, and DC power source for the Uninterruptible Power Supply (UPS). The major equipment includes:

- A bank of lead acid storage battery
- Two 100% capacity battery chargers
- Two (2) DC power distribution switchboard

Emergency Diesel Generator - The emergency diesel generator provides for the supply of essential AC auxiliary power during an electrical system (grid) black-out to permit a safe and orderly shutdown of the plant equipment. The major equipment includes:

- 1,000 kW diesel generator w/load bank
- 6,000 gallon diesel storage tank

Demineralized Water System - The demineralized water system functions to provide a supply of demineralized make-up water to the ST condenser hotwell, the CT evaporative cooling system, the CT water injection (NOx control on distillate), and for some the CT wash water solutions. The demineralized water system is sized to handle make-up when the plant is normally operating on natural gas fuel. During back-up operation on distillate fuel oil a rental trailer must be brought in to keep up with the water injection demand of the CTs. Major equipment that makes up the demineralized water treatment system includes the following:

- Multimedia filters for pre-filtration,
- Sodium bi-sulfite feed system
- Antiscalant chemical feed system
- Reverse Osmosis (RO) system
- Electro deionization (EDI) polishing
- Two (2) 100% capacity demineralized water transfer pumps
- A 200,000 gallon demineralized water storage tank

Facility Low Voltage Electrical System - The low voltage electrical system conditions and distributes electrical power at various voltage levels for lighting, receptacles and small loads (motors, HVAC, etc.) as required for all buildings and site support facilities. The major equipment of this system includes:

- Transformers
- Distribution panel boards
- Disconnect switches
- Separately mounted motor starters
- General-purpose receptacles
- Welding receptacles
- Lighting

Fuel Gas Condition Skid- The fuel gas skid functions to filter and heat the natural gas supplied for use as fuel by the combustion turbine and HRSG duct burner. A skid is provided for each CTG. Fuel gas heating is performed during startup by an electric heater to provide the superheat necessary to prevent the formation of liquid hydrocarbons in the fuel. During normal operation the fuel gas is heated by a performance heater using high temperature boiler feedwater to enhance the thermal performance of the CTG. The major equipment for each skid includes the following:

- Two (2) 100% coalescing filter/separators
- One (1) 100% scrubber
- One (1) fuel gas performance heater
- One (1) fuel gas electric startup heater

Fuel Gas Pressure Regulating Skid – A dual train fuel gas pressure regulating skid shall be provided to filter and regulate the supply pressure of the natural gas to the facility to satisfy the operational requirements of the CTGs. The major pressure regulation skid equipment includes the following:

- One (1) emergency shutdown valve
- Two (2) 100% capacity coalescing filter/separators
- Two (2) 100% capacity pressure reducing trains each equipped with the following:
- * One (1) automatic inlet isolation valve per train
- * One (1) startup pressure reducing valve per train
- * One (1) primary pressure reducing valve per train
- One (1) safety relief valve with vent stack
- One (1) fuel gas condensate drains tank

Fire Protection System - The fire protection system provides standpipes and hose stations, fire extinguishers, independent fire detection systems, and fixed carbon dioxide suppression systems to protect personnel, plant buildings and equipment from the hazards of fire. The system consists of the following:

- Low-pressure carbon dioxide fire suppression system
- Fire detection systems
- Portable fire extinguishers
- Manual fire alarm systems
- Manual pull stations in the buildings
- Fire Protection Control Panel for alarm, indication of system status, and actuation of fire protection equipment.
- One (1) 100% electric driven fire pump
- One (1) 100% diesel driven fire pump with diesel day tank.
- One (1) jockey pump
- 300,000 gallons of fire water reserve within the raw water storage tank
- Piping and valves, stand pipes and hose stations
- Fire pump building

Boiler Feedwater System - The boiler feedwater system functions to pressurize and transfer de-aerated condensate from the HRSG low-pressure drum to the high and intermediate pressure steam drums. The feedwater system also provides water to the MS and RH steam attemporators, and the steam bypass desuperheating stations associated with the ST steam bypass to the condenser. The major components of the feedwater system for each HRSG include the following:

- Two (2) 100% boiler feed pumps per HRSG
- Two (2) automatic pump minimum flow recirculation control valves per HRSG
- One (1) HP and one (1) IP feedwater control valve per HRSG

Grounding System - The grounding system function to provide protection for personnel and equipment from the hazards that can occur during power system faults and lightning strikes. System design shall include the ability to detect system ground faults. The grounding system shall typically consist of copper-clad ground rods, bare and insulated copper cable, copper bus bars, copper wire mesh, exothermic connections, and air terminals.

Generation (High Voltage) Electrical System- The generation electrical system functions to deliver generator power to the Substation, and provides power for the auxiliary electrical system. One set of the following equipment shall be provided for each the three (3) generating unit).

- Generator main leads
- Generator breaker
- Generator step-up (GSU) transformer (230 kV), (345kV Location 3 Only)
- Auxiliary transformer

Main Steam System - The main steam (MS) system functions to convey high pressure steam to the HP steam turbine section. During normal operation steam flows from each HRSG though the main steam headers into the steam turbine. The major equipment includes:

- Flow measuring equipment for steam flow
- Isolation valves
- Piping, valves and accessories

Hot Reheat and Cold Reheat Steam Systems – The hot reheat (HR) and cold reheat (CR) steam systems function to convey intermediate pressure steam to the intermediate pressure section of the steam turbine. During normal operation (CR) steam flows from the HP turbine exhaust to the HRSG reheater, and from the HRSG reheater steam flows through the HR steam system to the IP turbine inlet. The major equipment includes:

- Isolation valves
- Piping, valves and accessories

Oily Waste System - The Oily Waste system collects oil-contaminated wastewater in the plant drains system. The oil waste system is gravity feed throughout the plant to an oil water separator. The solids and oil collected in this system will be collected for offsite disposal at a suitable, licensed, hazardous waste facility. The effluent from the oil/water separator will be discharged to the local sewer system.

Plant Instrument and Service Air System - The plant instrument and service air system function to supply clean, dry, oil-free air at the required pressure and capacity for all pneumatic controls, transmitters, instruments and valve operators, and clean compressed air for non-essential plant service air requirements. The plant instrument and service air system includes the following components:

- Two (2) full capacity, air cooled, single stage, rotary screw type air compressors, each complete with controls, instrument panel, intercooler, lubrication system, aftercooler, moisture separator, intake filter-silencer, air/oil separator system and an unloading valve.
- Two (2) full capacity air receivers
- Two (2) full capacity, dual tower, heaterless type desiccant air dryers
- Two (2) full capacity pre-filters
- Two (2) full capacity after-filters
- Associated header and distribution piping and valves

Plant Communication System - The plant communication system functions to provide the plant external communication system through the use of the public telephone system. The administration building, control room, maintenance and storage areas will be equipped with telephone jacks. The Owner shall provide any internal plant communication systems including, but not limited to, two-way radios.

Plant Security - The plant security system provides protection to the property and personnel. A security system consisting of card readers, intercoms, motor operated gate and fencing will be provided.

Potable Water - The potable water system serves as a water source for drinking and personnel hygiene needs. Potable water also serves as a water source for eyewash and safety shower stations. Potable Water will be supplied from the local water utility.

Raw Water System - The raw water system provides utility water for general plant use. The water will be provided by the local water utility. The raw water system will supply water for miscellaneous non-potable plant uses including demineralized water system supply, plant equipment wash-downs, makeup to the circulating water system, general service water and fire water. The major equipment includes the following:

- One (1) 500,000 gallon raw water/fire water storage tank
- Two (2) 100% capacity raw water pumps

Steam & Water Sample System - The steam and water sample system functions to collect, cool, condense, draw and analyze the feedwater supply stream, blowdown from the HRSG drum, and the HP steam to the steam turbine. A sample system is provided for each HRSG. The major equipment includes:

- One new sample panel/sink
- Sample coolers
- Analyzers
- Sample tubing, valves, fittings & supports
- Insulation and freeze protection
- Lab facilities necessary to provide analysis required herein

Sanitary Waste System - The sanitary waste system collects sanitary wastes from the plant and transports to the city sewer system.

Uninterruptible Power Supply (UPS) - The uninterruptible power supply functions to provide reliable, regulated low voltage ac power to critical equipment during normal and emergency operating conditions. The typical loads that are considered for connection to the UPS include the Distributed Control System (DCS), CEMS, the turbine supervisory instrumentation, transducer power supplies, burner management systems (BMS), critical instruments, emergency shutdown networks, and critical vendor supplied control panels. The UPS system consists of the following components:

- Static inverter
- Static transfer switch
- Alternate source transformer and line voltage regulator
- Manual make-before-break bypass switch
- Two ac circuit breakers (alternate input, and bypass source)
- One dc circuit breaker

- Vital 120 V ac distribution panel with fused disconnects
- Controls, indicating lights, meters and alarms to control the UPS

3.3.2 Dual Fuel – Combustion Turbines

The following additional equipment is required to support dual (distillate fuel & natural gas fuel) operation of the combustion turbines. It is in addition to the equipment listed above for gas fuel operation of the combustion turbines:

Fuel Oil System - The fuel oil system receives, stores, regulates and transports distillate oil for use as backup fuel in the combustion turbine. The major equipment includes:

- One (1) 2,000,000 gallon fuel oil storage tank with steel containment (over 1 day storage).
- Two (2) fuel unloading stations
- Two (2) 100% capacity fuel forwarding pumps
- Two (2) 100% capacity fuel transfer pumps
- Interconnecting power and instrument cable, piping valves, filters and accessories

Fire Protection System – The fire protection system will be expanded to include the distillate fuel unloading area and the distillate fuel storage tanks.

Demineralized Water System – The demineralized water system will be expanded to support dual fuel operation of the CTs. This include the addition of demineralized water piping to the CTs water injection system and interconnecting piping, foundation and power feeds required to support operation of a trailer mounted water treatment system. In addition the storage capacity of the demineralized water storage tank will be increased to 2,250,000 gallons.

4.0 Power Plant General Arrangement

- Gas Fuel Only Combustion Turbine Arrangement, G-PP-002, revision A
- Dual Fuel Combustion Turbine Arrangement, G-PP-010, revision A

5.0 Project Schedule

A 32 month overall schedule (NTP-COD) was assumed which includes a 28 month construction/startup schedule through COD.

Project Start	April 2, 2012
NTP and Start of detailed engineering	October 1, 2012
Start of construction	January 14, 2013
COD	June 1, 2015

The overall schedule is essentially the same whether gas fuel only or dual fuel.

Prior to the NTP the Owner must obtain all the necessary environmental and local permits that are required as a prerequisite to commence construction. Procurement of OFE starts with project start and is complete for assignment to EPC contractor at NTP.

6.0 Capital Cost Estimate

EPC Contractor

- Estimate Basis, revision F

For Locations 1-5, Dual Fuel and Location 3 Single Fuel:

- Estimate Summary and Details, revision F

Owner

For Locations 1-5, Dual Fuel and Location 3 Single Fuel:

- Owner Cost tabulations

Fuel consumption and power generation during commissioning and testing (estimated) for the Combined Cycle plant is as follows:

operating hours	2847	hrs		
duration	119	days		
duration	17	weeks		
generation	546788	MWhrs	includes STG	
average load	192	MW		
fuel gas	4138657	Dth		
fuel oil	540,000	gals		

7.0 Cash Flow

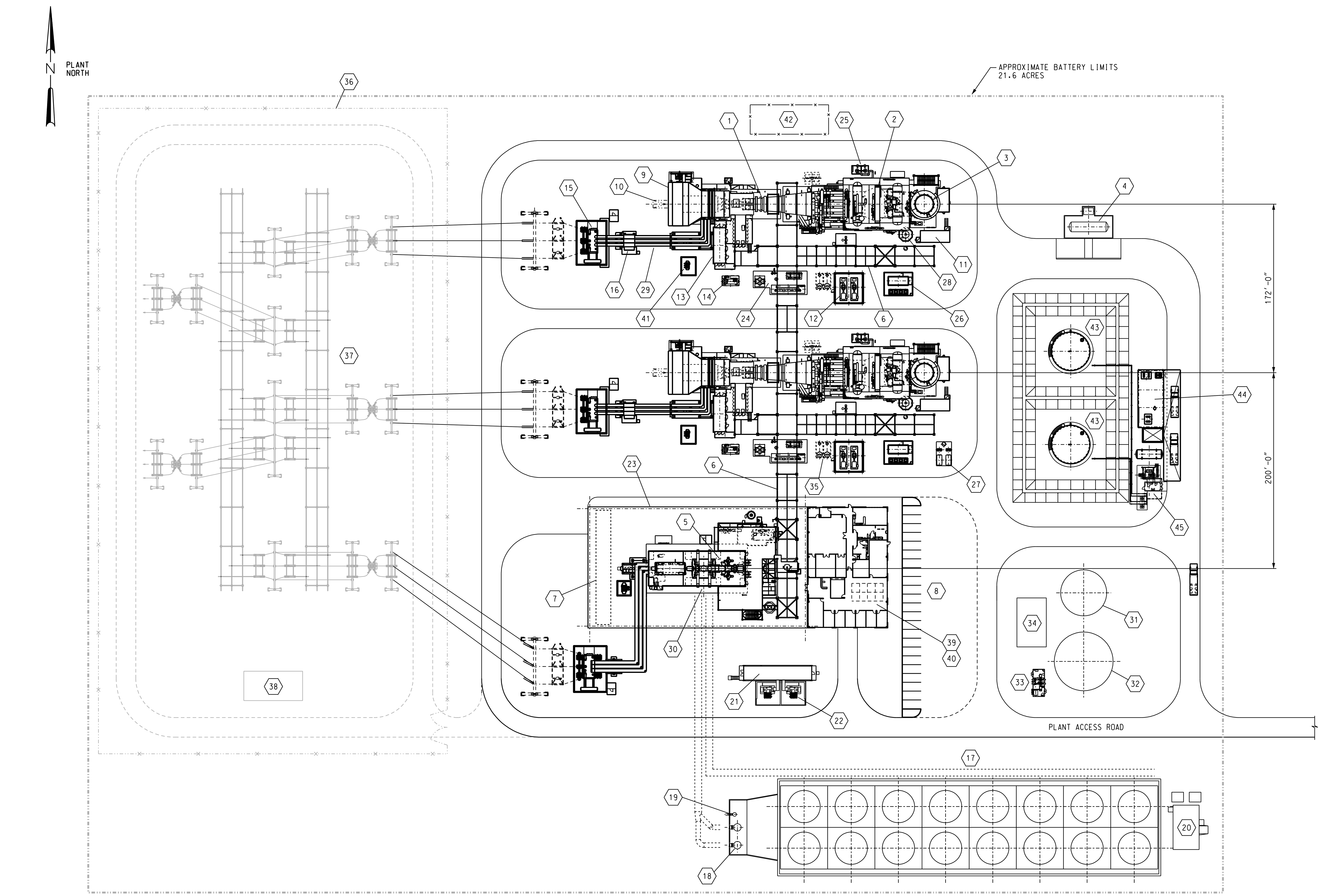
EPC cash flow is based on the project cost excluding the OFE portion paid by Owner prior to assignment but including the OFE portion after assignment. The percentages of OFE costs to be used are identified in the Owners cost tabulations in Section 6.0. There are no monthly charges until NTP and assignment.

Owner cash flow is based on the OFE portion paid prior to assignment and all sales taxes and runs from project start thru end of project. The percentages of OFE costs to be used are identified in the Owners cost tabulations in Section 6.0. Owner does not make OFE payments after assignment at NTP.

These two percentages cannot be added together to get total monthly cash flows. They have to be converted to cash first, and then added.

- Combined Cycle – Gas Fuel Only Cash Flow, revision F
- Combined Cycle – Dual Fuel Cash Flow, revision F

APPENDIX B.2. LAYOUT DRAWING FOR DUAL-FUEL CC



EQUIPMENT LEGEND

ITEM	EQPT TAG NO	DESCRIPTION
1		7FA CTG (COMBUSTION TURBINE GENERATOR)
2		HRSG W/ SCR
3		HRSG STACK
4		AMMONIA UNLOADING & STORAGE
5		D-11 STG (STEAM TURBINE GENERATOR)
6		PIPE/ELECTRICAL RACK
7		OVERHEAD BRIDGE CRANE
8		PARKING
9		CTG INLET AIR FILTER
10		CTG ROTOR PULL SPACE
11		CEMS (CONTINUOUS EMISSIONS MONITORING)
12		BOILER FEEDWATER PUMPS
13		PEEC
14		CO2 FIRE PROTECTION SYSTEM
15		GSU
16		GENERATOR BREAKER
17		COOLING TOWER
18		CIRCULATING COOLING WATER PUMPS
19		AUXILIARY COOLING WATER PUMP
20		COOLING TOWER CHEMICAL FEED ENCLOSURE
21		PDC (POWER DISTRIBUTION CENTER)
22		STATION SERVICE TRANSFORMERS
23		STG BUILDING
24		FUEL GAS CONDITIONING SKIDS
25		HRSG VAPORIZER SKID
26		HRSG CHEMICAL FEED SKID
27		PLANT/INSTRUMENT AIR COMPRESSORS
28		HRSG BLOWDOWN TANK
29		ISO PHASE BUS
30		MAIN STEAM CONDENSER
31		DEMINERALIZED WATER STORAGE TANK
32		RAW/FIRE WATER STORAGE TANK
33		FIRE PROTECTION PUMP PACKAGE
34		WATER TREATMENT BUILDING
35		HO/LO SUMPS
36		SWITCHYARD FENCE LINE
37		SWITCHYARD
38		SWITCHYARD CONTROL HOUSE
39		WAREHOUSE & MAINTENANCE BUILDING (GROUND FLR)
40		ADMINISTRATION BUILDING & CONTROL ROOM (2nd FLR)
41		EXCITATION TRANSFORMER
42		FUEL GAS METERING & REGULATING STATION
43		FUEL OIL STORAGE TANKS
44		FUEL OIL UNLOADING & FORWARDING
45		FOAM FIRE PROTECTION SYSTEM
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Scale: 1 INCH = 60 FEET

NO.	DATE	REVISION	BY	CHK
P1	06/29/11	ISSUED FOR INTRNAL REVIEW	TBJ	
A	08/23/11	ISSUED FOR FINAL REPORT	TBJ	

RESPONSIBLE ENGINEER
PE #

REVISION APPROVAL — REV A — DATE 08/23/11

DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL	.	ELECTRICAL	.
STRUCTURAL	.	INST & CNTRL	.
MECHANICAL	.	ARCHITECTURAL	.
PROCESS	.	PLANT LAYOUTS	.
PIPING	.		

STATUS

ISSUED	REV	DATE	DM	SDE	PEM
PRELIMINARY	P1	06/29/11			
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1" = 60'-0"

The Brattle Group
PJM Interconnect Study
Northeast U.S.

PROJECT NO. 421147

CH2MHILL
CH2MHILL Engineers, Inc.

GENERAL ARRANGEMENT
DUAL FUEL
2 x 1 COMBINED CYCLE
PLOT PLAN

DWG. NO. G-PP-010
REV. A

BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

FILENAME:
PLOT DATE:

APPENDIX B.3. PROJECT SCHEDULE FOR DUAL-FUEL CC

The Brattle Group

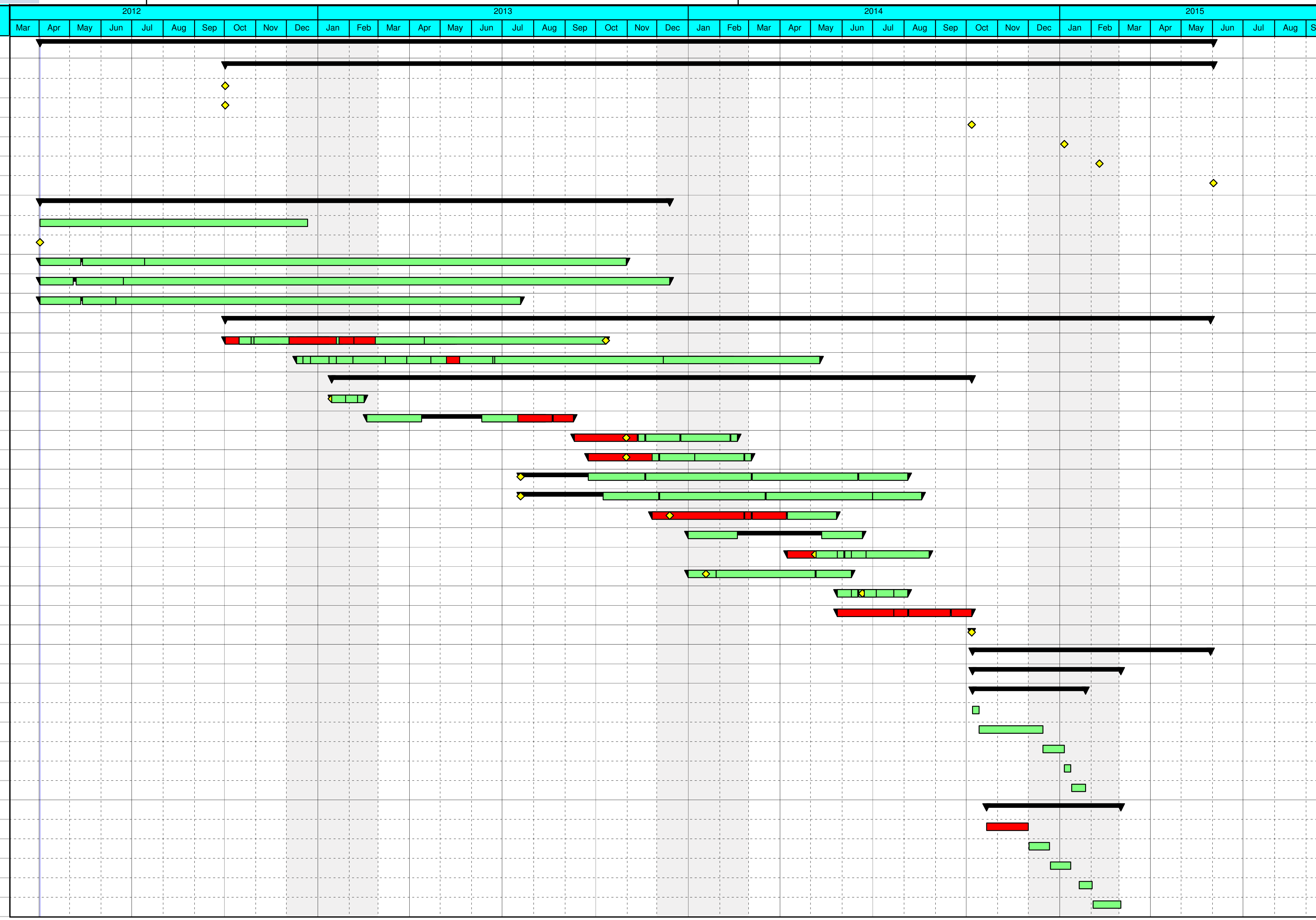
PJM Interconnect Study, Northeast US

Combined Cycle Plant (Dual Fuel)

Project # 421147

CH2MHILL

Activity ID	Activity Name	Start	Finish
	PROJECT	02-Apr-12	01-Jun-15
	CONTRACT MILESTONES	01-Oct-12	01-Jun-15
	NOTICE TO PROCEED	01-Oct-12*	
	ENGINEERING RELEASE	01-Oct-12	
	ELECTRICAL BACKFEED COMPLETE		06-Oct-14
	FUEL GAS AVAILABLE		06-Jan-15
	MECHANICAL COMPLETION		09-Feb-15
	COD		01-Jun-15
	OWNER TASKING	02-Apr-12	13-Dec-13
	PERMITTING	02-Apr-12*	21-Dec-12
	PROJECT START	02-Apr-12	
	CTG PROCUREMENT	02-Apr-12	31-Oct-13
	STG PROCUREMENT	02-Apr-12	13-Dec-13
	HRSG PROCUREMENT	02-Apr-12	19-Jul-13
	NTP-COD	01-Oct-12	29-May-15
	ENGINEERING	01-Oct-12	11-Oct-13
	PROCUREMENT	10-Dec-12	09-May-14
	CONSTRUCTION	14-Jan-13	06-Oct-14
	General Sitework	14-Jan-13	15-Feb-13
	Underground Piping & Electrical	18-Feb-13	09-Sep-13
	CTG UNIT #1 Erection	10-Sep-13	17-Feb-14
	CTG UNIT #2 Erection	24-Sep-13	03-Mar-14
	HRSG -1 Erection	19-Jul-13	04-Aug-14
	HRSG - 2 Erection	19-Jul-13	18-Aug-14
	STG -1 Erection	26-Nov-13	26-May-14
	GSU Transformers	31-Dec-13	20-Jun-14
	Site Buildings	08-Apr-14	25-Aug-14
	Cooling Tower	31-Dec-13	09-Jun-14
	Fuel Oil Storage & Transfer Facility	27-May-14	04-Aug-14
	Install Mechanical / Electrical BOP Systems	27-May-14	06-Oct-14
	Initiate Systems Release	06-Oct-14	06-Oct-14
	START UP & COMMISSION	07-Oct-14	29-May-15
	Unit # 1	07-Oct-14	02-Mar-15
	CTG Unit #1	07-Oct-14	26-Jan-15
	OIL FLUSH	07-Oct-14	13-Oct-14
	BOP SYSTEMS COMMISSIONING (CTG)	14-Oct-14	15-Dec-14
	FUNCTIONAL CHECKOUT	16-Dec-14	05-Jan-15
	FIRST FIRE UNIT # 1 (Gas)	06-Jan-15	12-Jan-15
	TUNE & PERFORMANCE/EMMISSION TESTING	13-Jan-15	26-Jan-15
	HRSG Unit #1	21-Oct-14	02-Mar-15
	BOP COMMISSIONING (HSRG)	21-Oct-14	01-Dec-14
	HYDRO TESTING	02-Dec-14	22-Dec-14
	CHEM CLEAN	23-Dec-14	12-Jan-15
	STEAM BLOWS	20-Jan-15	02-Feb-15
	RESTORE PIPING/MECH	03-Feb-15	02-Mar-15



Actual Work

Remaining Work

Critical Remaining Work

Page 1 of 2

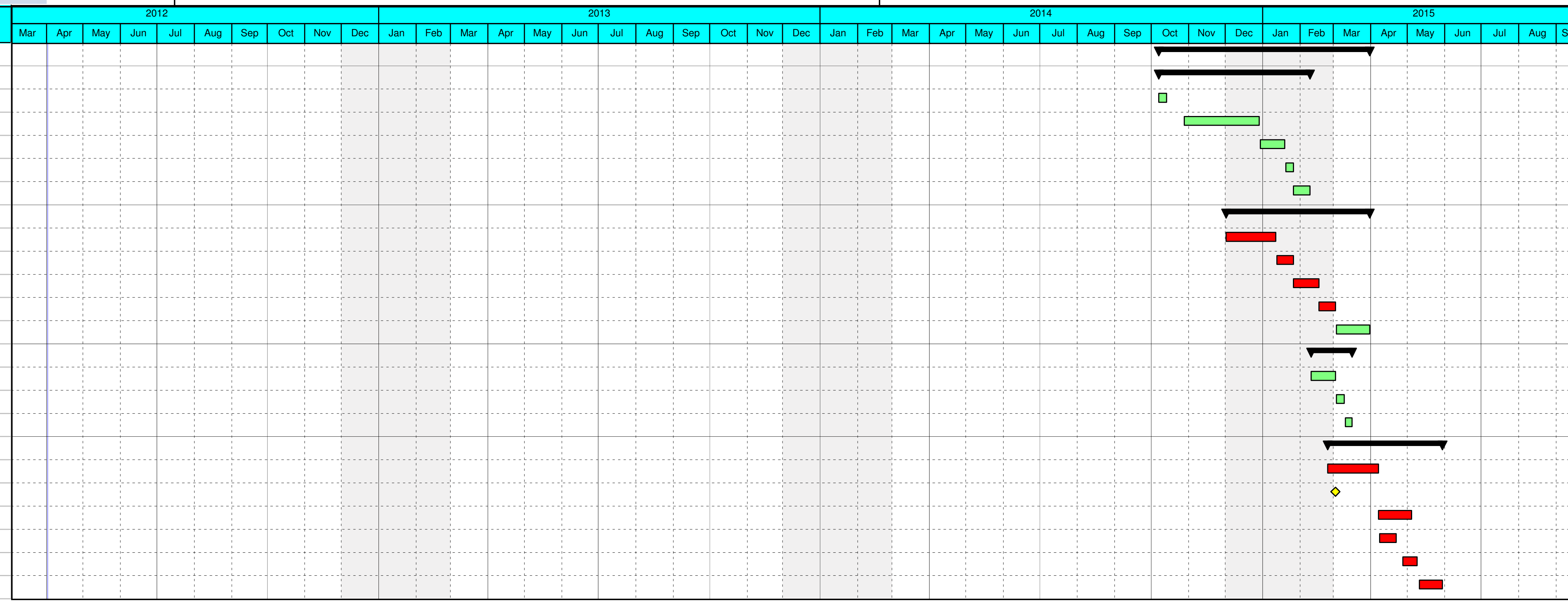
Level 1 SUMMARY SCHEDULE

PJM Interconnect Study, Northeast US

Combined Cycle Plant (Dual Fuel)

Project # 421147

Activity ID	Activity Name	Start	Finish
	Unit # 2	07-Oct-14	30-Mar-15
	CTG Unit # 2	07-Oct-14	09-Feb-15
	OIL FLUSH	07-Oct-14	13-Oct-14
	BOP SYSTEMS COMMISSIONING (CTG)	28-Oct-14	29-Dec-14
	FUNCTIONAL CHECKOUT	30-Dec-14	19-Jan-15
	FIRST FIRE UNIT # 2 (Gas)	20-Jan-15	26-Jan-15
	TUNE & PERFORMANCE/EMISSION TESTING	27-Jan-15	09-Feb-15
	HRSG Unit # 2	02-Dec-14	30-Mar-15
	BOP COMMISSIONING (HRSG)	02-Dec-14	12-Jan-15
	HYDRO TESTING	13-Jan-15	26-Jan-15
	CHEM CLEAN	27-Jan-15	16-Feb-15
	STEAM BLOW	17-Feb-15	02-Mar-15
	RESTORE PIPING/MECH	03-Mar-15	30-Mar-15
	Fuel Oil Storage & Transfer System	10-Feb-15	16-Mar-15
	System Commissioning	10-Feb-15	02-Mar-15
	CTG #1 First Fire (Oil)	03-Mar-15	09-Mar-15
	CTG # 2 First Fire (Oil)	10-Mar-15	16-Mar-15
	STG Unit #1	24-Feb-15	29-May-15
	BOP COMMISSIONING	24-Feb-15	06-Apr-15
	STG ON TURNING GEAR		02-Mar-15
	VACUUM TEST	07-Apr-15	04-May-15
	STEAM & GENERATOR TEST FUNCTIONAL TESTING	08-Apr-15	21-Apr-15
	GENERATOR SYNC	27-Apr-15	08-May-15
	FULL LOAD	11-May-15	29-May-15



🟦 Actual Work
🟩 Remaining Work
🟥 Critical Remaining Work

Level 1 SUMMARY SCHEDULE

APPENDIX B.4. COST DETAIL FOR CC IN CONE AREA 1

Project Name	701 MW 2x1 CC Plant - GE 7241FA.05															**Data Date**						
Client	The Brattle Group									Location 1: Dual Fuel						**Print Date**	**24-Jul-11**					
Project Description	Middlesex County, New Jersey															**Rev:**	**F**					

				Professional Labor		**Self Perform Craft Labor**		**Subcontract Labor**		**Specialty Sub.**	**Total Craft**	**Material**			**Const.**	**Specialty**			**% Of Direct**	**% Of Project**	**% Of Project**	
Description	**Quantity**	**UM**	**HRS / UM**	**Hours**	**Labor Amount**	**Hours**	**Labor Amount**	**Hours**	**Labor Amount**	**Hours**	**Hours**	**Eng. Equip**	**Bulk**	**Sub.**	**Equip.**	**Sub**	**Other**	**Total**	**Total**	**Total Revenue**	**Total**	
DIRECT COSTS																						
Concrete	14,940	CY	9.09 MH/CY			135,791h	10,100,010	0h	-	0h	135,791h	-	4,241,693			-		14,341,703	6.3%	4.0%	2.7%	
Steel	1,526	TN	22.37 MH/TN			37,988h	3,255,887	0h	-	0h	37,988h	-	4,286,600			-		7,542,488	3.3%	2.1%	1.4%	
Piping	84,006	LF	3.00 MH/LF							0h								-	0.0%	0.0%	0.0%	
Above Ground	59,619	LF	3.63 MH/LF			216,410h	18,917,159	0h	-	0h	216,410h		12,768,089					31,685,248	13.9%	8.9%	6.0%	
Below Ground	24,387	LF	1.48 MH/LF			36,011h	3,147,874	0h	-	0h	36,011h		1,934,368					5,082,242	2.2%	1.4%	1.0%	
Electrical										0h								-	0.0%	0.0%	0.0%	
Wire & Cable	1,242,931	LF	0.05 MH/LF			61,421h	5,777,517	0h	-	0h	61,421h	2,429,804	-					8,207,321	3.6%	2.3%	1.5%	
Cable Tray	14,800	LF	0.90 MH/LF			13,320h	1,252,929	0h	-	0h	13,320h	-	444,000					1,696,929	0.7%	0.5%	0.3%	
Conduit	198,214	LF	0.14 MH/LF			27,294h	2,567,401	0h	-	0h	27,294h	-	1,089,748					3,657,149	1.6%	1.0%	0.7%	
Instrumentation	1	LS				26,118h	2,456,757	0h	-	0h	26,118h	2,368,200	218,462			-		5,043,419	2.2%	1.4%	0.9%	
Heat Tracing	1	LS								12,662h	12,662h					4,092,000		4,092,000	1.8%	1.1%	0.8%	
Gas Turbine	1	LS				71,789h	5,590,187	0h	-	0h	71,789h	-	400,000					5,990,187	2.6%	1.7%	1.1%	
Steam Turbine	1	LS				57,973h	4,514,343	0h	-	0h	57,973h	-	285,000					4,799,343	2.1%	1.3%	0.9%	
HRSG / Boiler / OTSG	1	LS				206,448h	16,076,100	0h	-	0h	206,448h	-	50,000					16,126,100	7.1%	4.5%	3.0%	
Condenser	1	LS				4,940h	384,678	0h	-	0h	4,940h	3,100,000	100					3,484,778	1.5%	1.0%	0.7%	
Cooling Tower	1	LS								16,116h	16,116h					5,208,500		5,208,500	2.3%	1.5%	1.0%	
Air Cooled Condenser	1	LS				0h	-	0h	-	0h	0h	-	-			-		-	0.0%	0.0%	0.0%	
GSU Transformers	1	LS				1,080h	101,589	0h	-	0h	1,080h	8,930,000	6,000			-		9,037,589	4.0%	2.5%	1.7%	
Mechanical BOP	1	LS				20,404h	1,588,823	0h	-	14,968h	35,372h	12,173,822	80,936			4,837,500		18,681,081	8.2%	5.2%	3.5%	
Electrical BOP	1	LS				30,752h	2,892,613	0h	-	309h	31,061h	6,914,905	491,598			100,000		10,399,116	4.6%	2.9%	2.0%	
Relocation / Demolition Equipment	1	LS								0h						-		-	0.0%	0.0%	0.0%	
Sitework	1	LS				0h	-	13,090h	1,692,192	5,752h	18,842h	-	41,334			1,859,090		3,592,616	1.6%	1.0%	0.7%	
Buildings & Architectural	1	LS								9,948h	9,948h					3,214,880		3,214,880	1.4%	0.9%	0.6%	
Insulation	1	LS								6,845h	6,845h					2,212,268		2,212,268	1.0%	0.6%	0.4%	
Painting	1	LS								1,343h	1,343h					434,027		434,027	0.2%	0.1%	0.1%	
Fire Protection	1	LS								0h	0h							-	0.0%	0.0%	0.0%	
HVAC / Plumbing	1	LS								0h	0h							-	0.0%	0.0%	0.0%	
Heavy haul	1	LS								9,283h	9,283h					3,000,000		3,000,000	1.3%	0.8%	0.6%	
Switchyard	1	LS								0h	0h					-		-	0.0%	0.0%	0.0%	
Premium Time, Shift Differential	1	LS																-	0.0%	0.0%	0.0%	
Bussing	1	LS																-	0.0%	0.0%	0.0%	
Indirect Services & Support	1	LS				20,811h	1,739,600	0h	-	960h	21,771h		788,688		116,000	310,300		2,954,589	1.3%	0.8%	0.6%	
Temporary Facilities & Services	1	LS				2,975h	248,714	0h	-	13,618h	16,593h		812,552		402,248	4,400,970		5,864,484	2.6%	1.6%	1.1%	
Small Tools & Consumables	1	LS				0h	-	0h	-	0h	0h		4,152,218					4,152,218	1.8%	1.2%	0.8%	
Construction Equip, Operators, Testing,	1	LS				74,846h	6,256,409	0h	-	246h	75,092h		1,352,318		4,158,336	79,530		11,846,593	5.2%	3.3%	2.2%	
Scaffolding	1	LS				66,342h	5,545,530	0h	-	0h	66,342h							5,545,530	2.4%	1.6%	1.0%	
Startup Craft Labor, Materials, Supplies	1	LS				41,220h	5,853,293	0h	-	5,647h	46,867h		654,000		475,000	1,825,000		8,807,293	3.9%	2.5%	1.7%	
Freight	1	LS										1,629,506	1,776,830					3,406,336	1.5%	1.0%	0.6%	
Export / Import - Warehousing, Loading/Unloading, Warehousing, Customs																		-	0.0%	0.0%	0.0%	
Buy Downs	1	LS																-	0.0%	0.0%	0.0%	
																		-	0.0%	0.0%	0.0%	
Project Indirects (Taxes, Insurances, Bonds, Other)																	18,333,820	18,333,820	8.0%	5.1%	3.4%	18,333,820
																		-	0.0%	0.0%	0.0%	
SUBTOTAL DIRECT COSTS				0h	-	1,153,932h	**98,267,414**	13,090h	**1,692,192**	97,697h	1,264,719h	**37,546,237**	**35,874,535**	-	**5,151,584**	**31,574,065**	**18,333,820**	**228,439,847**	**100.0%**	**64.1%**	**42.9%**	**228,439,847**
			Avg. Rate																			
			/ Hour →↓				$ 85.16		$ 129.27							$ 129.27						

Project Name	701 MW 2x1 CC Plant - GE 7241FA.05	**Data Date**	
Client	The Brattle Group Location 1: Dual Fuel	**Print Date**	**24-Jul-11**
Project Description	Middlesex County, New Jersey	**Rev:**	**F**

CH2MHILL

				Professional Labor		Self Perform Craft Labor		Subcontract Labor		Specialty Sub.	Total Craft		Material			Const.	Specialty			% Of Direct	% Of Project	% Of Project	
Description	**Quantity**	**UM**	**HRS / UM**	**Hours**	**Labor Amount**	**Hours**	**Labor Amount**	**Hours**	**Labor Amount**	**Hours**	**Hours**	**Eng. Equip**	**Bulk**	**Sub.**	**Equip.**	**Sub**	**Other**	**Total**	**Total**	**Total Revenue**	**Total**	
INDIRECT COSTS																						
PROJECT MANAGEMENT	32,140	HRS																				4,224,367
Home Office Professional (PM/CM)			186.36	7,279h	1,356,425													1,356,425	0.6%	0.4%	0.3%	
Project Support Professional (Safe/QC/PC/DocC/Est)			128.17	14,422h	1,848,494													1,848,494	0.8%	0.5%	0.3%	
Clerical			56.81	10,440h	593,102													593,102	0.3%	0.2%	0.1%	
Expenses																	426,347	426,347	0.2%	0.1%	0.1%	
ENGINEERING	149,700	HRS																				16,097,528
Home Office Professional			96.91	143,300h	13,887,657													13,887,657	6.1%	3.9%	2.6%	
Field Professional (Site Support Engineering)			109.71	6,400h	702,127													702,127	0.3%	0.2%	0.1%	
Value Center Engineering																		-	0.0%	0.0%	0.0%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	1,507,744	1,507,744	0.7%	0.4%	0.3%	
PROCUREMENT	14,000	HRS																				1,600,000
Home Office Professional			110.00	14,000h	1,540,000													1,540,000	0.7%	0.4%	0.3%	
Field Professional																		-	0.0%	0.0%	0.0%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	60,000	60,000	0.0%	0.0%	0.0%	
SITE MANAGEMENT	172,247	HRS																				16,550,609
Field Professional			109.73	133,710h	14,671,638													14,671,638	6.4%	4.1%	2.8%	
Clerical			32.72	38,537h	1,260,828													1,260,828	0.6%	0.4%	0.2%	
Expenses																	618,143	618,143	0.3%	0.2%	0.1%	
STARTUP MANAGEMENT	38,472	HRS																				3,937,483
Home Office Professional			110.00	552h	60,720													60,720	0.0%	0.0%	0.0%	
Field Professional			93.70	37,920h	3,553,096													3,553,096	1.6%	1.0%	0.7%	
Clerical																		-	0.0%	0.0%	0.0%	
Expenses																	323,667	323,667	0.1%	0.1%	0.1%	
SUBTOTAL MANGEMENT COST				406,560h	**39,474,087**	1,153,932h	**98,267,414**	13,090h	**1,692,192**	97,697h	1,264,719h	**37,546,237**	**35,874,535**	-	**5,151,584**	**31,574,065**	**21,269,721**	**270,849,835**	**118.6%**	**76.0%**	**50.9%**	**270,849,835**
CONTINGENCY																						Cont. & Escal.
Percentage					5.0%		7.0%		7.0%			12.3%	5.0%		5.0%	6.0%						50,834,214
Dollars					1,973,704		6,878,719		118,453			4,636,387	1,793,727		257,579	1,894,444		17,553,014	7.7%	4.9%	3.3%	
ESCALATION																						
Percentage					10.3%		12.2%		7.5%			16.7%	15.5%		11.3%	13.9%	1.4%					
Dollars					4,074,800		11,976,300		126,200			6,282,400	5,549,000		584,000	4,395,400	293,100	33,281,200	14.6%	9.3%	6.3%	
RISK																		-	0.0%	0.0%	0.0%	
PROJECT SUBTOTAL				406,560h	**45,522,592**	1,153,932h	**117,122,433**	13,090h	**1,936,846**	97,697h	1,264,719h	**48,465,024**	**43,217,262**	-	**5,993,163**	**37,863,909**	**21,562,821**	**321,684,048**	**140.8%**	**90.3%**	**60.4%**	**321,684,048**

Project Name	701 MW 2x1 CC Plant - GE 7241FA.05		**Data Date**	
Client	The Brattle Group	Location 1: Dual Fuel	**Print Date**	**24-Jul-11**
Project Description	Middlesex County, New Jersey		**Rev:**	**F**

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Description	Quantity	UM	HRS / UM	Professional Labor Hours	Professional Labor Labor Amount	Self Perform Craft Labor Hours	Self Perform Craft Labor Labor Amount	Subcontract Labor Hours	Subcontract Labor Labor Amount	Specialty Sub. Hours	Total Craft Hours	Material Eng. Equip	Material Bulk	Material Sub.	Const. Equip.	Specialty Sub	Other	Total	% Of Direct Total	% Of Project Total Revenue	% Of Project Total	G&A & Margin
GENERAL OVERHEAD & ADMINISTRATION																						40,968,405
Percentage					0.0%		0.0%		0.0%			0.0%	0.0%		0.0%	0.0%	0.0%					
Dollars					-		-		-			-	-		-	-	-	-	0.0%	0.0%	0.0%	
MARGIN																						
Percentage					10.0%		10.0%		10.0%			10.0%	10.0%		10.0%	10.0%	10.0%					
Dollars					4,552,259		11,712,243		193,685			4,846,502	4,321,726		599,316	3,786,391	2,156,282	32,168,405	14.1%	9.0%	6.0%	
POWER BLOCK MARGIN																						
Percentage												0.0%										
Dollars												-						-	0.0%	0.0%	0.0%	
Assignment Fee For Owner Supplied Equipment																			0.0%	0.0%	0.0%	
Percentage												5.0%										
Dollars												8,800,000						8,800,000	3.9%	2.5%	1.7%	
PROJECT COST W/MARKUPS				406,560h	**50,074,851**	1,153,932h	**128,834,676**	13,090h	**2,130,530**	97,697h	1,264,719h	**62,111,526**	**47,538,988**	**-**	**6,592,479**	**41,650,299**	**23,719,103**	**362,652,453**	**158.8%**	**101.8%**	**68.1%**	**362,652,453**
Sales Tax Deduction																		(6,465,565)	-2.8%	-1.8%	-1.2%	(6,465,565)
Management Adjustments																		-	0.0%	0.0%	0.0%	
PROJECT TOTAL REVENUE				406,560h	**50,074,851**	1,153,932h	**128,834,676**	13,090h	**2,130,530**	97,697h	1,264,719h	**62,111,526**	**47,538,988**	**-**	**6,592,479**	**41,650,299**	**23,719,103**	**356,186,888**	**155.9%**	**100.0%**	**66.9%**	**356,186,888**
OWNER FURNISHED EQUIPMENT																		-	0.0%		0.0%	
CTGs												93,000,000						93,000,000	40.7%		17.5%	
												-						-	0.0%		0.0%	
HRSGs												41,000,000						41,000,000	17.9%		7.7%	
STG												42,000,000						42,000,000	18.4%		7.9%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
												-						-	0.0%		0.0%	
																		-	0.0%		0.0%	
																		-	0.0%		0.0%	-
																		-	0.0%		0.0%	
																		-	0.0%		0.0%	
PROJECT TOTAL				406,560h	**50,074,851**	1,153,932h	**128,834,676**	13,090h	**2,130,530**	97,697h	1,264,719h	**238,111,526**	**47,538,988**	**-**	**6,592,479**	**41,650,299**	**23,719,103**	**532,186,888**	**233.0%**	**100.0%**	**100.0%**	**356,186,888**

532,187,000

APPENDIX B.5. CASH FLOW SCHEDULE FOR CC IN CONE AREA 1

The Brattle Group

701 MW 2x1 CC Plant - GE 7241FA.05

EPC Cashflow

08/15/11 Dual Fuel MONTH		Rev. Monthly %	F - Supplemental CUMULATIVE %
1	Apr-12	0.000%	0.000%
2	May-12	0.000%	0.000%
3	Jun-12	0.000%	0.000%
4	Jul-12	0.000%	0.000%
5	Aug-12	0.000%	0.000%
6	Sep-12	0.000%	0.000%
7	Oct-12	4.434%	4.434%
8	Nov-12	3.212%	7.646%
9	Dec-12	1.666%	9.312%
10	Jan-13	1.931%	11.243%
11	Feb-13	3.474%	14.718%
12	Mar-13	2.785%	17.502%
13	Apr-13	2.975%	20.478%
14	May-13	3.100%	23.578%
15	Jun-13	4.729%	28.307%
16	Jul-13	3.447%	31.753%
17	Aug-13	4.344%	36.097%
18	Sep-13	3.914%	40.011%
19	Oct-13	6.914%	46.925%
20	Nov-13	4.689%	51.615%
21	Dec-13	2.696%	54.310%
22	Jan-14	3.734%	58.045%
23	Feb-14	3.856%	61.900%
24	Mar-14	3.186%	65.086%
25	Apr-14	3.736%	68.823%
26	May-14	4.039%	72.862%
27	Jun-14	4.039%	76.902%
28	Jul-14	3.521%	80.423%
29	Aug-14	3.339%	83.762%
30	Sep-14	3.247%	87.009%
31	Oct-14	2.759%	89.768%
32	Nov-14	2.150%	91.918%
33	Dec-14	1.571%	93.489%
34	Jan-15	1.327%	94.816%
35	Feb-15	1.022%	95.839%
36	Mar-15	0.992%	96.831%
37	Apr-15	0.748%	97.579%
38	May-15	0.230%	97.809%
39	Jun-15	2.191%	100.000%

The Brattle Group

701 MW 2x1 CC Plant - GE 7241FA.05

Owner Cash Flow

08/15/11 Dual Fuel MONTH	Rev. Monthly %	F - Supplemental CUMULATIVE %
1	0.00%	0.00%
2	31.63%	31.63%
3	0.00%	31.63%
4	0.00%	31.63%
5	25.79%	57.42%
6	15.82%	73.24%
7	0.03%	73.27%
8	0.59%	73.87%
9	1.86%	75.72%
10	0.90%	76.63%
11	0.92%	77.54%
12	1.69%	79.23%
13	1.00%	80.23%
14	0.99%	81.23%
15	1.07%	82.30%
16	1.58%	83.88%
17	1.12%	85.00%
18	1.15%	86.15%
19	1.17%	87.32%
20	2.81%	90.13%
21	1.59%	91.72%
22	0.60%	92.32%
23	0.59%	92.91%
24	0.54%	93.44%
25	0.64%	94.08%
26	0.64%	94.72%
27	0.61%	95.33%
28	0.51%	95.84%
29	0.55%	96.39%
30	0.50%	96.89%
31	0.45%	97.34%
32	0.42%	97.76%
33	0.27%	98.03%
34	0.23%	98.25%
35	0.20%	98.45%
36	0.19%	98.64%
37	0.16%	98.80%
38	0.11%	98.92%
39	1.08%	100.00%

APPENDIX C. WOOD GROUP O&M COST ESTIMATES

Wood Group cost estimates for each simple-cycle and combined-cycle plant fixed and variable operation and maintenance costs are included in this Appendix. These costs are reported in their components related to an annual facility fees as well as the costs of a long-term service agreement.

Wood Group GTS
Power Plant Services

August 5, 2011

Kathleen Spees
The Brattle Group
44 Brattle Street
Cambridge, MA 02138

Re: The Brattle Group Plant Evaluations

Kathleen:

We have estimated here the variable and fixed costs associated with operating CT and CC plants of several configurations. These costs are presented in two components:

1. Life Cycle Operations and Maintenance (O&M) Fees
2. Long-term Service Agreement (LTSA) Costs

We look forward to discussing this and answering any of your questions.

Sincerely yours,

Ted Kowalski
Vice President, Product Management
Wood Group Power Plant Services, Inc.
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Assumptions

- **Equipment Descriptions**

We have developed cost estimates for three plant configurations, one combined cycle configuration, and two simple cycle configurations as listed below. The simple cycle configurations are identical except that one is fitted with Selective Catalytic Reduction (SCR), and the other is not. In all cases these estimates are consistent with a dual fuel plant that uses distillate fuel oil as a backup fuel under emergency conditions. The numbers we report here for Will County, IL can be used for either a dual fuel or a non-dual fuel plant.

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	With SCR: 418 MW at 59 °F Without SCR: 420 MW at 59 °F	Baseload (w/o Duct Firing): 627 MW at 59 °F Maximum Load (w/ Duct Firing): 701 MW at 59 °F
Cooling System	n/a	Cooling Tower
Power Augmentation	Evaporative Cooling	Evaporative Cooling
Blackstart Capability	None	None
On-Site Gas Compression	None	None

- **Location and Labor Type**

For each plant configuration, we have estimated costs in each of five locations with labor rates consistent with union or non-union labor as listed.

CONE Area	Plant Location	Labor
1 Eastern MAAC	Middlesex, NJ	Union
2 Southwest MAAC	Charles, MD	Non-Union
3 Rest of RTO	Will, IL	Union
4 Western MAAC	Northampton, PA	Union
5 Dominion	Fauquier, VA	Non-Union

Life Cycle Costs

We report here the life cycle operating costs for each plant configuration, including pre-mobilization costs and ongoing annual fees for a plant with an online date of June 1, 2015. For all years after the five years we report, these fees would be escalated at a 2.5% inflation rate. For year 1, we have reported the breakdown between fixed costs and variable costs included in these fees. The proportion of cost breakdown would be constant over the plant life assuming the same number of hours and starts reported here. These variable costs are additive with the variable costs reported for the LTSA.

This does not include Owner's costs such as property tax, plant insurance, or asset management.

Will County, IL Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Will County, IL

Pre Operation - Mobilization	
12 Month Period - Jun 1, 2014 to May 31, 2015	**US$**
Facility Labor & Program Implementation	$ 521,103
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 994,649**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,379,047	$ 1,413,524	$ 1,448,862	$ 1,485,083	$ 1,522,210
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,767,682**	**$ 2,836,874**	**$ 2,907,795**	**$ 2,980,491**	**$ 3,055,003**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,379,047		$ 1,379,047	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 969,985***	***$ 140,471***	***$ 829,514***	***$ 0.83***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,767,682**	**$ 146,792**	**$ 2,620,890**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Charles County, MD Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Charles County, MD

Pre Operation - Mobilization	
12 Month Period - Jun 1, 2014 to May 31, 2015	**US$**
Facility Labor & Program Implementation	$ 509,039
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 982,585**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,300,035	$ 1,332,536	$ 1,365,849	$ 1,399,995	$ 1,434,995
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,688,669**	**$ 2,755,886**	**$ 2,824,783**	**$ 2,895,403**	**$ 2,967,788**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,300,035		$ 1,300,035	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 969,985***	***$ 140,471***	***$ 829,514***	***$ 0.83***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,688,669**	**$ 146,792**	**$ 2,541,877**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Middlesex County, NJ Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Middlesex County, NJ

Pre Operation - Mobilization *12 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 548,759
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 1,022,305**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 1,473,690	$ 1,510,532	$ 1,548,296	$ 1,587,003	$ 1,626,678
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,862,324**	**$ 2,933,883**	**$ 3,007,229**	**$ 3,082,411**	**$ 3,159,471**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,473,690		$ 1,473,690	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 969,985***	***$ 140,471***	***$ 829,514***	***$ 0.83***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,862,324**	**$ 146,792**	**$ 2,715,532**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Northampton County, PA Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Northampton County, PA

Pre Operation - Mobilization	
12 Month Period - Jun 1, 2014 to May 31, 2015	**US$**
Facility Labor & Program Implementation	$ 487,945
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 961,491**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,260,467	$ 1,291,978	$ 1,324,278	$ 1,357,385	$ 1,391,319
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,649,101**	**$ 2,715,329**	**$ 2,783,211**	**$ 2,852,792**	**$ 2,924,112**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,260,467		$ 1,260,467	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 969,985***	***$ 140,471***	***$ 829,514***	***$ 0.83***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,649,101**	**$ 146,792**	**$ 2,502,309**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Fauquier County, VA Simple Cycle without SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC
Power Facility located in Fauquier County, VA

Pre Operation - Mobilization *12 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 499,050
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 261,546
Total Mobilization Cost	**$ 972,596**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016*	*June 1, 2016* *May 31, 2017*	*June 1, 2017* *May 31, 2018*	*June 1, 2018* *May 31, 2019*	*June 1, 2019* *May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,254,444	$ 1,285,805	$ 1,317,950	$ 1,350,899	$ 1,384,671
Consumables	$ 175,097	$ 179,475	$ 183,961	$ 188,561	$ 193,275
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 429,116	$ 439,843	$ 450,840	$ 462,111
TOTAL Multi-Year Annual Fee Summary	**$ 2,643,078**	**$ 2,709,156**	**$ 2,776,884**	**$ 2,846,306**	**$ 2,917,464**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,254,444		$ 1,254,444	
			$ -	
Consumables	$ 175,097	$ 12,001	$ 163,096	$ 0.07
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 969,985***	***$ 140,471***	***$ 829,514***	***$ 0.83***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,649	$ 6,321	$ 412,328	$ 0.04
TOTAL	**$ 2,643,078**	**$ 146,792**	**$ 2,496,286**	**$ 0.87**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Will County, IL Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Will County, IL

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 770,282
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,131,328**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary	*June 1, 2015* *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 1,379,047	$ 1,413,524	$ 1,448,862	$ 1,485,083	$ 1,522,210
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,773,944**	**$ 2,843,294**	**$ 2,914,375**	**$ 2,987,235**	**$ 3,061,915**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,379,047		$ 1,379,047	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 975,978*	*$ 146,464*	*$ 829,514*	*$ 0.87*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,773,944**	**$ 153,055**	**$ 2,620,890**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Charles County, MD Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Charles County, MD

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 747,269
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,108,315**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016*	*June 1, 2016* *May 31, 2017*	*June 1, 2017* *May 31, 2018*	*June 1, 2018* *May 31, 2019*	*June 1, 2019* *May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,300,035	$ 1,332,536	$ 1,365,849	$ 1,399,995	$ 1,434,995
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,694,932**	**$ 2,762,306**	**$ 2,831,363**	**$ 2,902,147**	**$ 2,974,701**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,300,035		$ 1,300,035	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	*$ 975,978*	*$ 146,464*	*$ 829,514*	*$ 0.87*
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,694,932**	**$ 153,055**	**$ 2,541,877**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Middlesex County, NJ Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Middlesex County, NJ

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 799,603
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,160,650**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,473,690	$ 1,510,532	$ 1,548,296	$ 1,587,003	$ 1,626,678
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,868,587**	**$ 2,940,302**	**$ 3,013,809**	**$ 3,089,155**	**$ 3,166,383**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,473,690		$ 1,473,690	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 975,978***	***$ 146,464***	***$ 829,514***	***$ 0.87***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,868,587**	**$ 153,055**	**$ 2,715,532**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Northampton County, PA Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Northampton County, PA

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 731,962
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,093,008**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016*	*June 1, 2016* *May 31, 2017*	*June 1, 2017* *May 31, 2018*	*June 1, 2018* *May 31, 2019*	*June 1, 2019* *May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 1,260,467	$ 1,291,978	$ 1,324,278	$ 1,357,385	$ 1,391,319
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,655,364**	**$ 2,721,748**	**$ 2,789,792**	**$ 2,859,537**	**$ 2,931,025**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,260,467		$ 1,260,467	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 975,978***	***$ 146,464***	***$ 829,514***	***$ 0.87***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,655,364**	**$ 153,055**	**$ 2,502,309**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Fauquier County, VA Simple Cycle with SCR

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x Frame 7FA SC w/SCR
Power Facility located in Fauquier County, VA

Pre Operation - Mobilization *06 Month Period - Jun 1, 2014 to May 31, 2015*	**US$**
Facility Labor & Program Implementation	$ 732,068
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 149,046
Total Mobilization Cost	**$ 1,093,114**

Hours of Operation	
Weeks / Year	50
Days / Week	2
Hours / Day	5
Hours / Year	**500**
Starts / Year	**50**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 1,254,444	$ 1,285,805	$ 1,317,950	$ 1,350,899	$ 1,384,671
Consumables	$ 181,090	$ 185,618	$ 190,258	$ 195,015	$ 199,890
Office Administration	$ 161,347	$ 165,381	$ 169,515	$ 173,753	$ 178,097
Maintenance & Minor Repairs	$ 633,541	$ 649,379	$ 665,614	$ 682,254	$ 699,310
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 429,392	$ 440,127	$ 451,130	$ 462,408
TOTAL Multi-Year Annual Fee Summary	**$ 2,649,341**	**$ 2,715,575**	**$ 2,783,464**	**$ 2,853,051**	**$ 2,924,377**

June 1, 2015 to May 31, 2016 - Projected Costs

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 1,254,444		$ 1,254,444	
			$ -	
Consumables	$ 181,090	$ 17,994	$ 163,096	$ 0.11
Office Administration	$ 161,347	$ 5,014	$ 156,333	$ 0.03
Maintenance & Minor Repairs	$ 633,541	$ 123,456	$ 510,085	$ 0.73
Subtotal	***$ 975,978***	***$ 146,464***	***$ 829,514***	***$ 0.87***
Purchasing, Handling, Corporate, & Administrative Charges	$ 418,919	$ 6,591	$ 412,328	$ 0.04
TOTAL	**$ 2,649,341**	**$ 153,055**	**$ 2,496,286**	**$ 0.91**

Note: When online, units assumed to be at 100% maximum load for variable cost calculation.

Will County, IL Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Will County, IL

Pre Operation - Mobilization	
12 Month Period	**US$**
Facility Labor and Program Implementation	$ 2,302,001
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,776,245**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 May 31, 2016	*June 1, 2016 May 31, 2017*	*June 1, 2017 May 31, 2018*	*June 1, 2018 May 31, 2019*	*June 1, 2019 May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 3,631,653	$ 3,722,445	$ 3,815,506	$ 3,910,893	$ 4,008,666
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,584,169**	**$ 6,748,771**	**$ 6,917,491**	**$ 7,090,428**	**$ 7,267,691**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 3,631,653		$ 3,631,653	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	*$ 2,466,522*	*$ 1,325,166*	*$ 1,432,267*	*$ 0.66*
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,584,169**	**$ 1,384,799**	**$ 5,490,281**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

Charles County, MD Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC Power Facility located in Charles County, MD

Pre Operation - Mobilization 12 Month Period	US$
Facility Labor and Program Implementation	$ 2,232,371
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,706,615**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016*	*June 1, 2016* *May 31, 2017*	*June 1, 2017* *May 31, 2018*	*June 1, 2018* *May 31, 2019*	*June 1, 2019* *May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 3,454,910	$ 3,541,282	$ 3,629,814	$ 3,720,560	$ 3,813,574
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,407,425**	**$ 6,567,609**	**$ 6,731,799**	**$ 6,900,095**	**$ 7,072,599**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			Variable Cost
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 3,454,910		$ 3,454,910	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	*$ 2,466,522*	*$ 1,325,166*	*$ 1,432,267*	*$ 0.66*
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,407,425**	**$ 1,384,799**	**$ 5,313,537**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

Middlesex County, NJ Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Middlesex County, NJ

Pre Operation - Mobilization 12 Month Period	**US$**
Facility Labor and Program Implementation	$ 2,414,955
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,889,199**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 3,880,667	$ 3,977,684	$ 4,077,126	$ 4,179,054	$ 4,283,530
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,833,182**	**$ 7,004,010**	**$ 7,179,110**	**$ 7,358,589**	**$ 7,542,555**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 3,880,667		$ 3,880,667	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	***$ 2,466,522***	***$ 1,325,166***	***$ 1,432,267***	***$ 0.66***
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,833,182**	**$ 1,384,799**	**$ 5,739,295**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

Northampton County, PA Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Northampton County, PA

Pre Operation - Mobilization 12 Month Period	**US$**
Facility Labor and Program Implementation	$ 2,163,772
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,638,015**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016* **Year 1**	*June 1, 2016* *May 31, 2017* **Year 2**	*June 1, 2017* *May 31, 2018* **Year 3**	*June 1, 2018* *May 31, 2019* **Year 4**	*June 1, 2019* *May 31, 2020* **Year 5**
Labor	$ 3,338,601	$ 3,422,066	$ 3,507,618	$ 3,595,308	$ 3,685,191
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,291,117**	**$ 6,448,393**	**$ 6,609,603**	**$ 6,774,843**	**$ 6,944,216**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			**Variable Cost**
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 3,338,601		$ 3,338,601	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	***$ 2,466,522***	***$ 1,325,166***	***$ 1,432,267***	***$ 0.66***
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,291,117**	**$ 1,384,799**	**$ 5,197,229**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

Fauquier County, VA Combined Cycle

Wood Group Power Plant Services
Cost Plus Estimate for a 2 x 1 Frame 7FA CC
Power Facility located in Fauquier County, VA

Pre Operation - Mobilization 12 Month Period	US$
Facility Labor and Program Implementation	$ 2,159,263
Facility Costs	$ 212,000
Purchasing, Handling, Corporate, & Administrative Charges	$ 262,244
Total Mobilization Cost	**$ 2,633,506**

Hours of Operation	
Weeks / Year	50
Days / Week	5
Hours / Day	20
Hours / Year	**5,000**
Starts / Year	**150**

Multi-Year Annual Fee Summary

	June 1, 2015 *May 31, 2016*	*June 1, 2016* *May 31, 2017*	*June 1, 2017* *May 31, 2018*	*June 1, 2018* *May 31, 2019*	*June 1, 2019* *May 31, 2020*
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Labor	$ 3,310,788	$ 3,393,557	$ 3,478,396	$ 3,565,356	$ 3,654,490
Consumables	$ 1,069,272	$ 1,096,003	$ 1,123,403	$ 1,151,488	$ 1,180,276
Office Administration	$ 216,029	$ 221,429	$ 226,965	$ 232,639	$ 238,456
Maintenance & Minor Repairs	$ 1,181,221	$ 1,210,751	$ 1,241,020	$ 1,272,046	$ 1,303,847
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 498,143	$ 510,597	$ 523,362	$ 536,446
TOTAL Multi-Year Annual Fee Summary	**$ 6,263,303**	**$ 6,419,884**	**$ 6,580,381**	**$ 6,744,891**	**$ 6,913,515**

June 1, 2015 to May 31, 2016

	Year 1 Total Costs			Variable Cost
	TOTAL	**Variable**	**Fixed**	**$/MWh**
Facility staff labor costs	$ 3,310,788		$ 3,310,788	
			$ -	
Consumables	$ 1,069,272	$ 1,128,759	$ 299,050	$ 0.14
Office Administration	$ 216,029	$ 1,205	$ 214,019	$ 0.10
Maintenance & Minor Repairs	$ 1,181,221	$ 195,201	$ 919,198	$ 0.42
Subtotal	***$ 2,466,522***	***$ 1,325,166***	***$ 1,432,267***	***$ 0.66***
Purchasing, Handling, Corporate, & Administrative Charges	$ 485,993	$ 59,632	$ 426,361	$ 0.19
TOTAL	**$ 6,263,303**	**$ 1,384,799**	**$ 5,169,415**	**$ 0.85**

Note: When online, units assumed to be at 80% maximum load for variable cost calculation.

LTSA Budgets

- There are many different contract payment structures where the cash flow varies on an annual basis because of the delivery schedule of the parts for a scheduled event, and when the major maintenance events occur based on the plant's operations. Plant operations will determine how long it takes for the plant to reach the total factored fired starts (FFS) or factored fired hours (FFH) limit requiring such a maintenance event to be scheduled. For your purposes, we understand the LTSA costs are intended to reflect the total variable costs of the LTSA including major equipment costs incurred during these maintenance events (including combustion and hot gas path parts).
- The simple cycle and combined cycle plants were modeled with nominal operating profiles of 50 starts and 150 starts per year, respectively, although the resulting variable cost numbers would be consistent with a range of operating profiles
- We assumed a seventeen (17) year contract
- The Simple Cycle configuration would have the same LTSA budget on a $/FFS and $/FFH basis with or without an SCR
- The nominal dollars reported are for the year starting June 1, 2015 and would be escalated with a 2.5% inflation rate thereafter
- For both the simple cycle and combined cycle plant, LTSA fees would be assessed on either an FFS basis or an FFH basis. If the plant is operating at greater than **27** FFH/FFS, the maintenance intervals would be hours based, otherwise the costs would be assessed on a starts basis.

There are several factors that will affect the maintenance intervals regardless of whether the unit is hours or starts based . For example, fuel type, trips, type of NOx control, operational considerations, etc. will all affect how the FFS and FFH are calculated. General Electric GER3620, Heavy-Duty Gas Turbine Operating and Maintenance Considerations, provides details for why these factors affects the maintenance intervals.

Simple Cycle Inspection Schedule

Project Name:	Brattle Group - 50 Starts Simple Cycle
Project Location:	Various
Date:	2015-06-01

Date	Date End	Unit	Inspection Type
2023-09-24	2023-09-30	GT02	CI
2024-03-17	2024-03-23	GT01	CI
2032-09-24	2032-10-05	GT02	HGPI
2033-03-17	2033-03-28	GT01	HGPI

Combined Cycle Inspection Schedule

Project Name:	Brattle Group USA- 150 Starts Combined Cycle
Project Location:	Various
Date:	2015-06-01

Date	Date End	Unit	Inspection Type
2017-01-26	2017-02-01	GT02	CI
2017-11-09	2017-11-15	GT01	CI
2020-01-26	2020-02-06	GT02	HGPI
2020-11-09	1900-01-20	GT01	HGPI
2023-01-26	2023-02-01	GT02	CI
2023-11-09	2023-11-15	GT01	CI
2026-01-26	2026-02-06	GT02	HGPI
2026-11-09	2026-11-20	GT01	HGPI
2029-01-26	2029-02-01	GT02	CI
2029-11-09	2029-11-15	GT01	CI
2032-01-26	2032-02-22	GT02	MI
2032-11-09	2032-12-01	GT01	MI

LTSA Costs

Project Name: Brattle Group - LTSA Variable Costs			
	Simple Cycle	Combined Cycle	
	$/FFS	**$/FFS**	**$/FFH**
Will County, IL	$ 18,565	$ 9,700	$ 291
Charles County, MD	$ 17,501	$ 9,144	$ 274
Middlesex County, NJ	$ 19,846	$ 10,370	$ 311
Northampton County, PA	$ 16,968	$ 8,866	$ 266
Fauquier County, VA	$ 16,887	$ 8,823	$ 265

Attachment E

2011 RPM Performance Assessment

The Brattle Group

Second Performance Assessment of PJM's Reliability Pricing Model

Market Results 2007/08 through 2014/15

August 26, 2011

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PJM Interconnection, L.L.C.

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EXECUTIVE SUMMARY

The Brattle Group has been commissioned by PJM Interconnection L.L.C. ("PJM") to evaluate the performance of its Reliability Pricing Model ("RPM"), as required periodically under the PJM tariff. The scope of our evaluation includes: (1) a review of all Base Residual Auctions ("BRAs") and Incremental Auctions ("IAs") conducted to date to assess RPM's effectiveness in encouraging and sustaining sufficient capacity investments for reliability; (2) stakeholder interviews to identify key areas of concern; (3) an engineering cost estimate of the Cost of New Entry ("CONE") for each of five CONE Areas; (4) an evaluation of individual RPM design elements, including the Variable Resource Requirement ("VRR") curve, the Energy and Ancillary Service ("E&AS") offset methodology, and other design elements identified by stakeholders; (5) a probabilistic simulation analysis of RPM's performance; and (6) development of recommendations for possible modifications to improve the effectiveness of RPM.

Our primary finding is that RPM is performing well. Despite concerns by some stakeholders, RPM has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements. Resource adequacy requirements have been met or exceeded in both the Regional Transmission Organization ("RTO") and, during the last four BRAs, in all of the individual Locational Deliverability Areas ("LDAs") at capacity prices below the net cost of new entry ("Net CONE"). Year-to-year capacity price changes have been consistent with market fundamentals, reflecting changes in the supply and demand for capacity. RPM has reduced costs by fostering competition among all types of new and existing capacity, including demand-side resources. It has also facilitated decisions regarding the economic tradeoffs between investment in environmental retrofits on aging coal plants or their retirement.

Stakeholders have raised a number of key concerns. We find, however, that several major criticisms of RPM are contradicted by evidence available to date—most notably the arguments that RPM prices are too high, that RPM does not support investment in new generation of the right types in the right places, or that RPM cannot maintain reliability in the face of environmental retirements. Stakeholders expressed particular concerns about the volatility and unpredictability of RPM prices. Some of the observed price changes are consistent with changes in market fundamentals, which necessarily must be reflected in prices for the market to be efficient. Others are caused by the one-time implementation of various improvements to the initial RPM design, such as modeling more LDAs or elimination of Interruptible Load for Reliability ("ILR"). These impacts on prices reflect a non-recurring one-time adjustment, which is not a concern going forward. However, price uncertainty remains high due to non-transparent, and possibly excessive, fluctuations in modeled transmission limits and other administratively-defined parameters in RPM. We thus recommend a number of refinements to make the determination of transmission limits and administrative parameters more stable and transparent. To increase forward price transparency and facilitate long-term contracting, we also support the development of voluntary auctions or an over-the-counter trading platform for long-term capacity products.

Finally, we have identified several performance risks stemming from the RPM design that should be addressed to ensure that resource adequacy will be met going forward. To address these concerns, we recommend the implementation of six safeguards that would mitigate the identified performance risks. First, we recommend calibrating the E&AS offset methodology to E&AS margins actually earned by generation plants similar to the reference technology, which may increase Net CONE in some LDAs. Second, we recommend raising the price cap of the VRR curve to mitigate under-procurement risks. The higher cap will avoid the collapse of the VRR curve following anomalously high E&AS margins, which could result in reserve margins that remain well below reliability requirements. The higher cap will also avoid deterring offers with costs that temporarily exceed the *current* cap due to large differences between actual and administrative Net CONE values. Third, we recommend modeling constrained LDAs more proactively for locations where significant amounts of plant retirements are likely.

Fourth, we recommend maintaining the 2.5% overall Short-Term Resource Procurement Target ("STRPT") for the total resource requirement, but eliminating the "holdback" for Annual and Extended Summer resources. Fifth, we recommend introducing audits of demand-side resources to confirm their contractual and physical ability to respond as often and seasonally as claimed. And finally, we recommend establishing exemptions to the Minimum Offer Price Rule ("MOPR") to better support competitive entry through bilateral and self-supply arrangements.

The report explains these and other more minor recommendations for possible refinements to the RPM design that could further improve market efficiency. It also summarizes the results of the CONE study we conducted, including our recommendations about the choice between levelization methods. The detailed engineering cost study is documented in our separate report, *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM* ("CONE Report").

A. RPM Auction Results to Date

RPM introduced a capacity market design based on three-year forward annual auctions for locational capacity, with supply offers clearing against a downward sloping demand curve (the VRR curve). RPM is designed to achieve resource adequacy, improve price stability compared to the previous capacity market construct, and force existing resources to compete with a potentially large supply of new resources.

We previously assessed the overall effectiveness of RPM in our 2008 *Review of PJM's Reliability Pricing Model (RPM)*, which documented RPM auction results for the first five delivery years; from 2007/08 through 2011/12. Since then, three more base auctions have been conducted; the latest in May 2011 for the 2014/15 delivery year.

Based on our analysis of all RPM auctions conducted to date, we present the following findings:

- RPM has attracted and retained sufficient capacity to maintain resource adequacy in the RTO and in all LDAs, in spite of environmental and other challenges faced by suppliers. All regions have demonstrated capacity supplies in excess of their reliability requirements in all delivery years for which procurement was undertaken on a full three-year forward basis. Capacity resources were slightly below the reliability requirements during the first few delivery years in some LDAs, reflecting existing supply largely determined by pre-RPM conditions and a shorter-term forward procurement during the first four auctions that prevented most planned capacity from participating.

- Since RPM was implemented, a total of 28,400 MW of installed capacity ("ICAP") from new resources have been committed on an RTO-wide basis (not counting resources from Fixed Resource Requirement ("FRR") entities and new PJM members, FirstEnergy and Duke). These additions consist of 11,800 MW of demand side resources, 6,900 MW of increased imports and decreased exports, 4,800 MW of new generation, 4,100 MW of plant uprates, and 800 MW of plant reactivations. These resource additions are partially offset by 5,000 MW of retirements, 2,700 MW of plant derates, 6,800 MW of capacity initially offered into the RPM auctions by FRR entities but that was subsequently withdrawn to serve the entities own requirements, and 700 MW of otherwise excused resources. On net, the amount of committed capacity has increased by 13,100 MW, more than enough to meet reliability requirements.

- Similarly in all of the LDAs, net resource additions (including upgrades in transmission import capabilities) have been more than sufficient to meet reliability requirements. This occurred even in eastern LDAs, which showed resource deficiencies (relative to their reliability requirements) in the auctions for the first four delivery years. Furthermore, all areas have had significant amounts of uncleared offers from both new and existing resources, including new generation resources, that could have been procured at higher prices had those supplies been needed for reliability. Perhaps one exception is the PEPCO LDA, where little new generation has been offered, but resource adequacy has been maintained by new demand response ("DR") resources and uprates at prices that were well below the cost of new generation in three of the last four auctions.

- RPM has greatly facilitated competition among various types of capacity resources. The capacity market has attracted commitments from new generation. But it has attracted even larger amounts of new DR resources, retained existing generation, and supported the upgrade of existing plants at prices below the cost of new generation. Competition in RPM's centralized forward auctions has also allowed owners of aging coal plants to make more informed decisions about whether to invest in environmental retrofits or start planning to retire the units, particularly in the most recent auction for the 2014/15 delivery year.

- As a result of offers from a wide variety of new resources, particularly demand response resources, the BRA supply curves have become smoother and less steep over time, mitigating the steep offer curves in the first few auctions. This trend increased competition between resources in the recent auctions and will reduce price volatility going forward.

- Base Residual Auction prices have been consistent with the supply and demand for capacity, including transmission capabilities. Apart from the initial, compressed-schedule forward auctions that were dominated by pre-RPM supply conditions, prices have been below Net CONE because new generation was not needed to maintain resource adequacy given the availability of lower-cost, non-generation alternatives. Nevertheless, auction clearing prices were quite volatile, reflecting changes in market fundamentals, RPM rules, and RPM parameters.

- Clearing prices in the incremental auctions have been persistently below BRA prices, in part reflecting low incremental demand for capacity due to declines in load forecast and increased transmission capabilities. Furthermore, clearing prices and supply curves during the first few incremental auctions appear to have been disconnected from market fundamentals and BRA prices due to deficiencies in the initial auction design. Supply curves observed in the two incremental auctions conducted since the initial design was revised have been more consistent with offers observed in the respective BRAs. In the case of EMAAC, prices have also responded efficiently to declines in LDA import capabilities. Overall, however, the limited experience with the new, revised design does not yet allow for a full analysis of the performance of the incremental auctions.

B. STAKEHOLDER CONCERNS

We conducted interviews with eight groups of stakeholders: transmission owners, generation owners, electric distributors, end-use customers, other suppliers, financial analysts, state utility commissions, and PJM's Independent Market Monitor. The concerns they raised covered a wide range of topics. Stakeholder comments largely agreed on concerns over: (1) the uncertainty and unpredictability of RPM prices; (2) the volatility and lack of transparency in the determination of Capacity Emergency Transfer Limits ("CETL"); (3) the need for better coordination between RPM and transmission planning; (4) a lack of long-term contracting and the need to facilitate such contracting; (5) the potential impacts of EPA's new environmental rules; and (6) challenges created by the use of a historical E&AS offset.

Stakeholder opinions were divided, however, on a variety of topics, including concerns about: (1) a lack of new generation; (2) the treatment of existing and new capacity; (3) the level of CONE estimates; (4) load forecasts and reliability requirements; (5) the shape of the VRR curve; (6) the 2.5% short-term procurement target; (7) the performance and treatment of demand-response resources; (8) the appropriate number of LDAs; (9) the appropriateness of the length of the 3-year forward procurement period between the BRA and the delivery year; (10) how to facilitate long-term contracting; and (11) the efficiency and unintended consequences of the new Minimum Offer Pricing Rule ("MOPR").

Concerns raised by stakeholders are addressed throughout our report. While not all of these themes are RPM design issues, they nevertheless relate directly to capacity procurement costs and price uncertainty in the RPM market. These themes include RPM price uncertainty created by administrative parameters, the need for and the industry trends in long-term contracting, compensation for existing and new generation, the uncertainty created by the new environmental regulations, the dependability of DR, and the determination of reliability targets. Our findings in these areas are:

- *Price Volatility and Uncertainty*. Capacity prices have been volatile and uncertain, which increases the risks and therefore the costs faced by suppliers. Main causes are: (1) market fundamentals, whose effects on price signals should not be dampened; (2) the implementation of improvements to previous design elements regarding DR participation and LDA modeling which had a non-recurring impact on capacity prices; and (3) current methods of determining the value of administrative parameters, including CETL, locational reliability requirements, and load forecasts, which PJM should strive to make more stable and/or transparent.

- *The Lack of Long-Term Contracts*. Many generation projects proposed in PJM cannot obtain financing under the current market conditions. However, while some project developers may cast this as a market failure caused by the inadequacies of RPM or state retail choice constructs, we believe the primary reason that these projects cannot obtain financing is that they are not currently needed and are currently uncompetitive with alternative sources of capacity. In the future, when these projects are needed for resource adequacy, we expect that market prices will rise sufficiently to make these investments attractive. Nevertheless, we also recognize that it will be beneficial to both suppliers and customers if long-term contracts are facilitated and not hindered by RPM design and state retail regulation. To address long-term contracting concerns, we present options for increasing forward price transparency and offer recommendations to mitigate the perhaps unintended consequences of the recent modifications to MOPR.

- *Equal Compensation for Old and New Generation*. A number of state commissions expressed concern that RPM has maintained old generating plants with high emissions, compensating them as much as newer generation. With regard to environmental issues, we find that RPM is well designed to respond to existing environmental regulations and has successfully retained generation that complies with these existing standards. RPM should not be expected to serve as an indirect mean to impose tighter environmental standards than the state and federal governments have deemed appropriate. Moreover, trying to differentiate payments based on age would be inconsistent with a construct in which all resources are selling the same capacity product, and would lead to inefficiencies and higher costs in the long term.

- *Environmental Retirements*. Several stakeholders expressed concern about RPM's ability to replace or prevent simultaneous retirements of a large amount of generation caused by EPA's new environmental regulations. To date, RPM has responded well to such challenges due to its retrofit provisions, the forward period, and centralized clearing. So far, RPM has successfully and economically supported resource adequacy for the 2014/15 delivery year when EPA's new regulations become effective and over the 2009 through 2011 timeframe when Maryland implemented its Healthy Air Act. However, significant uncertainties remain as RPM has not yet been tested with larger amounts of simultaneous retirements within individual LDAs. It is consequently too early to tell how well RPM (or any other construct) will be able to address the challenges caused by the full slate of new EPA regulations planned to take effect between 2015 and 2018. Given the risks, we recommend that PJM continue to monitor potential retirements and implement safeguards such as a more proactive modeling of new LDAs.

- *The Dependability of Demand Response*. Generation and transmission owners expressed the concern that almost 10% of total resources cleared in the 2014/15 auction without assurance that so much DR can be developed and perform. The level of DR capacity committed for the 2014/15 delivery year is approximately 4,000 MW higher (in terms of unforced capacity or "UCAP") than the 10,900 MW of DR, energy efficiency ("EE"), and ILR resources that are already registered for the current 2011/12 delivery year—which appear to have been performing well during the recent heat wave. While substantial, the 4,000 MW increase over the next 3 years compares to a 6,000 MW increase over the past three years. Considering these trends and the fact that penalty provisions for deficiencies and performance violations are roughly comparable to those faced by generation, we anticipate adequate performance on average. However, we also recommend additional safeguards to ensure that all resources can perform as frequently and seasonally as claimed.

- *RPM Procurement Target*. Stakeholders raised concerns about the current methods used to determine the reliability requirement and the load forecast, which together determine the target level of procurement in RPM. We recognize that reviewing the targets themselves is not within the scope of our evaluation. However, in response to stakeholders' concerns, we offer recommendations for further examination of the targets and for improving transparency of the load forecasting process. We also recommend that PJM assess the economic benefits of selected target reserve margins and re-evaluate whether the 1-in-25 LDA reliability requirement should be modified to explicitly depend on the level of import dependence in the LDA and the probability of transmission outages.

C. ESTIMATES FOR THE NET COST OF NEW ENTRY

We recommend maintaining a combustion turbine ("CT") as the reference technology for the determination of Net CONE to define the VRR curve. Based on an examination of plants currently under construction in PJM and the U.S., and an analysis of likely future NO_X emissions standards, the reference plants are assumed to be configured as follows: a 390 MW (summer rating) greenfield CT plant with 2 GE 7FA.05 turbines with selective catalytic reduction ("SCR") for NOx control (only dry low-NO_X burners in Dominion), and evaporative cooling for power augmentation. Combined-cycle ("CC") plants were also evaluated based on a 2x1 configuration using GE 7FA.05 turbines, a cooling tower, SCR, evaporative cooling, and a total capacity of approximately 656 MW (summer rating), of which 72 MW is associated with duct firing.

For these CT and CC plant designs, we developed plant capital costs estimates working with CH2M HILL, a major EPC contractor. CH2M HILL relied on the same engineering cost models it currently uses to bid for actual projects. Resulting estimates of plant capital costs are reported here for each of five CONE areas of PJM. Details of this analysis are documented in the CONE Report prepared concurrently with this report.

The gross CONE is based on levelized plant capital costs plus estimated fixed operation and maintenance costs. The levelization calculation assumes balance-sheet financing by a merchant generator without a long-term power purchase agreement at an 8.5% after-tax weighted-average cost of capital ("ATWACC") and 20-year cost recovery. In Eastern Mid-Atlantic Area Council ("Eastern MAAC" or "EMAAC") for example, levelized CT costs are $134/kw-year ($367/MW-day) for the 2015/16 delivery year using the "level-nominal" capital charge rate method currently used in the RPM design. Our gross CONE estimate for EMAAC is 6% lower than the $142/kW-year ($389/MW-day) inflation-adjusted gross CONE estimate currently used in RPM.

We recommend that PJM and its stakeholders ***consider transitioning from the current "level-nominal" to a "level-real" capital charge rate methodology***. The "level-real" method assumes that the trajectory of future operating margins will grow with inflation as the net cost of new plants increases, which our analysis shows is consistent with the rate of historical cost increases. This recommendation is contingent on the adoption of our other recommendations (summarized below) to improve the E&AS offset and raise the price cap of the VRR curve. If implemented, the "level-real" capital charge rate would yield a gross CONE for 2015/16 of approximately $112/kW-year ($306/MW-day) for EMAAC. However, we estimate this $30/kW-year ($82/MW-day) decline in gross CONE estimates from the inflation-adjusted, current gross CONE will be approximately fully offset in eastern PJM by a lower, more accurate E&AS offset.

The administratively-determined E&AS offset currently over-estimates the E&AS margins actually earned by plants similar to the reference technology, especially in EMAAC and Southwestern MAAC. We consequently recommend that the ***calculation of the E&AS offset be improved to better reflect actual E&AS margins earned by similar plants***. Options include: (a) calibrating the dispatch algorithm used to estimate E&AS offsets so that it accurately reflects actual units' net revenues (*e.g.*, to incorporate significant participation in day-ahead markets even by CTs) or (b) that the E&AS offset be calculated directly from the net revenues earned by comparable new units (and regardless of whether these representative units are located in the same zone used to develop the gross CONE estimate). To reduce RPM price volatility, improve the timing of investment signals, and increase VRR curve performance, we also recommend that PJM and its stakeholders ***continue to explore options for developing either a normalized, forward-looking E&AS offset or an E&AS offset consistent with "equilibrium" market conditions at target reserve margins.*** Finally, we have assessed the potential for an empirical determination of Net CONE based on the bid information from new resources participating in the RPM auctions. Our analysis documents a very wide range of bid levels, leading us to the conclusion that this information is not useful to develop empirical estimates of Net CONE.

D. Increasing RPM Price Transparency and Stability

Significant changes in market fundamentals, including the unexpected swings in economic conditions, and several RPM design improvements implemented over the last several years have caused substantial swings in capacity prices. However, excess capacity price uncertainty remains that should be mitigated. The remaining sources of price uncertainty primarily relate to administrative parameters, including unexpected changes in LDA modeling, large and unexpected changes in LDA import constraints (CETL), and unexpected changes in load forecasts.

To reduce excess RPM price volatility, we offer a number of recommendations for further consideration and evaluation by PJM and its stakeholders. They include options that would ***increase CETL transparency and predictability*** (*e.g.*, by providing four, five and ten year CETL projections as part of the transmission planning process) and ***reduce the frequency of large CETL changes*** (*e.g.*, by introducing thresholds that help stabilize transmission plans). We also recommend that PJM and stakeholders consider options to ***improve coordination between RPM and PJM's transmission planning process*** (*e.g.*, by adding economic criteria to the reliability planning process and considering likely plant retirements), to ***minimize the likelihood that resource adequacy concerns related to plant retirements are addressed through reliability-must-run contracts***, and ***facilitate market-based responses to resource adequacy concerns*** that are identified through the transmission planning process.

To increase forward price transparency and facilitate bilateral long-term contracting, we also support PJM's effort to add centralized but voluntary auctions for long-term capacity products as a supplement to the 3-year forward base auctions (*e.g.*, for a duration of 3, 5, and 7 years starting with the BRA delivery year). Such ***voluntary long-term auctions or an over-the-counter trading platform for long-term capacity products*** would increase the transparency and liquidity of the long-term capacity market without risking the kinds of distortions that would be caused to auction prices if the prices for a single delivery year could be locked for multiple years in by broadening the New Entry Pricing Adjustment ("NEPA") or introducing mandatory long-term procurement.

E. SAFEGUARDING FUTURE RPM PERFORMANCE

While our analyses confirm that PJM has performed well to date, we also identified potential performance concerns. First, probabilistic market simulations identified potential performance problems with the current VRR curve when used in combination with historical E&AS offsets. These performance concerns are related to the current definition of the VRR curve cap (*i.e.*, point "a") as 1.5 × Net CONE. The simulations show that the current design risks the collapse of the entire VRR curve whenever historical energy margins spike (*e.g.*, due to unusual weather, outages, or other unexpected scarcity events). If E&AS offsets reach or exceed the value of CONE, the entire VRR curve disappears (*i.e.*, there is no demand for capacity), which can leave the market "stuck" at reserve margins that remain well below reliability targets. Even without a full collapse of the VRR curve, the current design does not provide the investment signals that can be depended upon to maintain reliability targets. This is the case whenever the historical E&AS offset is high, for example, and the cap of the VRR curve cap drops to levels less than generation developers' actual net cost of new entry.

To guard against such outcomes and maintain investment signals that can reasonably support achieving reliability targets, we recommend that PJM and stakeholders consider ***increasing the***

cap of the VRR curve such that the cap (point "a") exceeds the administratively determined value of Net CONE (point "b") by at least 0.5 × CONE and perhaps by as much as 1.0 × CONE (compared to the current cap, which exceeds point "b" by only 0.5 × Net CONE). This would reduce the likelihood that the cap is too low to attract offers under a variety of circumstances. It would also have avoided a problem encountered in SWMAAC, where a low price cap (relative to the price in the MAAC parent LDA) prevented the LDA from price-separating and continuing to procure local capacity in the 2010/11 auction in spite of shortages. Probabilistic market simulations indicate that increasing the VRR curve cap to 0.5 × CONE above point "b" would likely offset approximately 80% of the performance deterioration associated with the use of historical E&AS offsets. We also recommend that PJM ***clarify that the value of Net CONE cannot drop to levels less than zero*** for the purpose of defining points a, b, and c of the VRR curve and, as noted above, renew efforts to develop a normalized, forward looking or equilibrium E&AS offset.

In addition to modifying the VRR curve, we recommend that PJM and its stakeholders consider implementing a number of additional safeguards:

- ***Proactive LDA modeling***. To address potential locational resource adequacy challenges created by new environmental rules, we recommend that PJM proactively model LDAs in upcoming incremental and base residual auctions. We recommend that LDAs be modeled as soon as it appears that a significant amount of existing resources may be at risk for retiring within the LDAs. Resources at risk for retirement would be existing generation that did not clear in the most recent BRA or that have otherwise been determined to be at risk for retirement.

- ***Modify the 2.5% Short-Term Resource Procurement Target (STRPT)***. We recommend that PJM maintain the 2.5% overall STRPT but eliminate any "holdback" for Extended Summer and Annual resources. Holding back procurement of 2.5% of these higher-quality resources could suppress prices and lead to resource adequacy challenges in the face of retirement pressures on existing coal plants from new EPA regulations. Overall, we find that the STRPT does not distort capacity prices because more than 2.5% of total resources offered are unmitigated, allowing suppliers to freely adjust their offers or their decisions to participate in BRAs versus incremental auctions.

- ***Resource Verification***. We recommend that PJM and its stakeholders consider a number of refinements to the existing verification and enforcement provisions for demand-side resources. This would further improve the efficiency of RPM and ensure that all resources can perform as claimed. Our recommendations include testing of DR resources and expanding the resource registration process undertaken prior to each delivery year to include audits of contracts and physical loads to verify the capabilities of zonal resource portfolios to curtail as frequently and seasonally as represented, with appropriately penalties to provide incentives for DR providers to represent their resources accurately. This will allow PJM to confirm that resources can respond as often and seasonally as claimed. For example, this process would verify that resources providing "Annual" DR can respond in all seasons and do not have contractual limitations on the number of events.

- ***Exemptions from Minimum Offer Price Rule ("MOPR")***. We recognize that MOPR is important for preventing manipulation of RPM prices by buyers. However, we hope that the present proceeding on MOPR expands exemptions to prevent unintended consequences. Exemptions we recommend considering would apply to any capacity resource that is (1) procured under non-discriminatory competitive processes that are open to supplies from existing and new generation resources; or (2) self-supplied by entities that would not obtain net benefits from RPM price impacts, such as vertically-integrated load-serving entities and other resource owners (and their counterparties) that can demonstrate they do not have a significant net short position in RPM.

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Appendix: Summary of Stakeholder Comments

I. BACKGROUND

A. PURPOSE AND SCOPE OF THIS STUDY

The Brattle Group has been commissioned by PJM Interconnection L.L.C. ("PJM") to evaluate the performance and the overall design of its Reliability Pricing Model ("RPM"), as required periodically under the PJM tariff. The evaluation criterion is the effectiveness in meeting RPM's objective, which is to enable PJM to obtain sufficient resources to reliably meet the electricity needs of consumers within PJM. Several corollary objectives are to align capacity pricing with system reliability requirements, to provide transparent information to all market participants far enough in advance for actionable response, to support investment in demand-side resources and alternative supply resources as well as generation, to prevent boom-bust cycles in investments, to coordinate between RPM and Regional Transmission Planning ("RTEP"), and to reduce uncertainty in order to lower overall consumer cost to maintain reliable capacity supply in the long run. The specific scope of this assessment included:

1. A review of all Base Residual Auctions ("BRAs") and Incremental Auctions ("IAs") conducted to date (*i.e.*, through the 2014/15 delivery year) to assess the performance and overall effectiveness of RPM in encouraging and sustaining infrastructure investments;
2. Stakeholder interviews to identify key areas for performance assessment;
3. An evaluation of individual RPM design elements, in particular the Variable Resource Requirement ("VRR") curve and the Energy and Ancillary Service ("E&AS") offset methodology;
4. A simulation modeling analysis of the ability of RPM to reduce uncertainty and support investment sufficient to meet reliability requirements on a probabilistic basis;
5. An empirical and an engineering-cost assessment of the Cost of New Entry ("CONE") for each of five CONE Areas; and
6. Developing recommendations for possible modifications (if any) to improve the effectiveness of RPM.

We previously assessed the overall effectiveness of RPM in encouraging and sustaining infrastructure investments, documented the outcomes of the first five BRAs, analyzed the effectiveness of individual market design elements, and presented a number of recommendations for considerations by PJM and its stakeholders. The results of this prior assessment were presented in our June 2008 report reviewing RPM's performance ("2008 RPM Report").[1]

The remainder of this report is organized as follows. We first provide some background on RPM and summarize its current design. Section II discusses RPM auction results in detail, focusing on resource adequacy achieved and price signals sent under RPM. Section III of this report

[1] Pfeifenberger, Newell, Earle, Hajos, and Geronimo, *Review of PJM's Reliability Pricing Model (RPM)*, June 30, 2008.

summarizes comments received in our stakeholder interviews and discusses a number of key themes raised by stakeholders, such as concerns over price volatility and the lack of long-term contracting. Section IV summarizes our analysis of the current Cost of New Entry. Section V presents our analysis of VRR curve, including a probabilistic evaluation of the performance of the VRR curve prepared in cooperation with Professor Benjamin Hobbs based on the simulation model he previously developed and presented. And finally, in Section VI, we analyze a number of RPM and PJM market design elements and, for consideration and further evaluation by PJM and its stakeholders, identify aspects of these design elements that should be adjusted to improve the overall market effectiveness and provide additional safeguards to avoid RPM performance problems and resource adequacy shortfalls in light of future challenges such as the new Environmental Protection Agency ("EPA") regulations and continued reliance on the potentially volatile historical E&AS offsets.

B. RPM BACKGROUND

As we noted in our 2008 RPM Report, RPM replaced PJM's previous capacity market construct, the Capacity Credit Market ("CCM"), starting with the 2007/08 delivery year. The CCM, which had been in place since 1999, was a voluntary balancing mechanism that allowed Load Serving Entities ("LSEs") to satisfy their installed capacity ("ICAP") requirements on a daily, monthly, and multi-monthly basis. The CCM transacted less than 10% of the total PJM capacity obligation and was based on daily market clearing prices that were uniform across the entire PJM footprint. In addition, this original CCM did not include explicit market power mitigation rules, provided only weak performance incentives, and did not permit the participation of demand-side resources. The CCM resulted in capacity prices that, despite significant occasional spikes, were on average well below both the cost of adding new capacity and the cost of retaining some of the region's existing capacity. Importantly, without recognizing locational reliability requirements, the CCM also did not reflect reliability challenges and the higher value of capacity in certain import-constrained areas of PJM, particularly in parts of eastern PJM, such as the northern New Jersey, Delmarva, and Baltimore-Washington areas.

In contrast to CCM, the RPM capacity market design features a three-year forward-looking annual obligation for locational capacity that designed to improve price stability, enhance reliability, and force existing resources to compete with a potentially large supply of new resources. RPM includes a must-offer requirement for all capacity resources as well as mandatory participation by load. The RPM design also adds stronger performance incentives for generation, explicit market power mitigation rules, and direct participation of demand-side resources. RPM introduced an auction format in which offer-based supply curves are cleared against downward-sloping demand curves (the VRR curves) instead of vertical demand curves. The sloped demand curve design provides a number of benefits, including valuing capacity that is procured beyond that which is required to meet reliability requirements.

The stated purpose of RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of consumers within PJM. In fulfilling that function, PJM emphasizes that the RPM provides:

- Support for load-serving entities (LSEs) using self-supply to satisfy their capacity obligations for future years;

- A competitive auction to secure additional capacity resources, demand response ("DR"), and qualifying transmission upgrades to satisfy LSEs' unforced capacity ("UCAP") obligations that are not satisfied through self-supply;
- Recognition of the locational value of capacity resources; and
- A backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability.

RPM was approved by the Federal Energy Regulatory Commission ("FERC") in its order dated December 22, 2006 (Docket ER05-1410-001 *et al.*) after an extensive stakeholder and market design effort lasting more than two years. PJM initially filed a proposed RPM market design with FERC on August 31, 2005 to address the failure of the previous capacity market design to set prices adequate to ensure sufficient resources, which caused current and projected violations of PJM's reliability requirement, particularly in eastern PJM. FERC agreed in an April 20, 2006 order that the preexisting capacity market design was unjust and unreasonable and ordered further proceedings which led to settlement discussions involving more than 65 parties. This settlement effort led to the current RPM design that was filed on September 29, 2006 ("RPM Settlement") and approved by FERC in its December 22, 2006 order.

The first RPM auction took place in April 2007 and procured capacity for the 2007/08 delivery year. Four more were conducted within the next 12 months. The fifth auction, conducted in May 2008 auction for the 2011/12 delivery year, was the first to procure capacity under a full three-year forward commitment. Since then, three more auctions have been conducted with a full 3-year forward commitment, the most recent one in May 2011 for the 2014/15 delivery year.

Attachment DD of PJM's Open Access Transmission Tariff ("OATT") and PJM's Manual 18 describe the RPM market design in detail.[2] Various RPM overviews, training materials, and information for individual delivery years, auction design parameters, and summary auction results are also available online.[3] Additional materials, discussion documents, and agendas documenting the ongoing efforts to refine various aspects of RPM are posted under various stakeholder groups, particularly in the Markets and Reliability Committee (MRC).[4] Design overviews and detailed assessments of RPM auction results and performance to date have also been published by PJM's Independent Market Monitor ("IMM").[5]

C. SUMMARY OF THE CURRENT RPM DESIGN

We provided a detailed description of the RPM design in our 2008 RPM Report, some of which we repeat here for the convenience of providing a complete design summary. The key design parameters of RPM are:

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2 PJM's OATT and capacity market manual are publicly posted, see PJM (2011a, q).

3 For training materials, see "Reliability Pricing Model" in PJM (2011u); for auction results, parameters and related documentation, see PJM (2011v).

4 MRC and other stakeholder group meeting materials are available at PJM (2011w).

5 The market monitor publishes a report on the results of every base and incremental auction, as well as publishing reviews within the annual state of the market reports, see Monitoring Analytics (2011a).

- Base residual and incremental auctions that procure capacity and adjustments to capacity obligations on a forward basis;
- LDAs and locational capacity prices that are able to reflect the greater need for capacity in import-constrained areas;
- Provisions that allow demand-side resources and new transmission projects to compete with generating capacity;
- A downward sloping (rather than a vertical) demand curve, called the VRR curve;
- Administrative and empirical determinations of the net cost of new entry ("Net CONE");
- Performance monitoring during the delivery year and peak periods;
- Consistency with self-supply and bilateral procurement of capacity;
- An opt-out mechanism under the Fixed Resource Requirement (FRR) alternative;
- Explicit market monitoring and mitigation rules, including a must-offer requirement for existing generating resources and IMM review and mitigation of new entrant offers.

Base Residual and Incremental Auctions. The initial auctions procuring forward capacity resources for particular delivery years are referred to as Base Residual Auctions or BRAs, in reference to the fact that the auctions procure the residual resources required after taking into account resources self-supplied by load serving entities through asset ownership or long-term bilateral contracts. Each base auction is followed by three "Incremental Auctions"—23 months, 13 months, and 4 months before each delivery year—that can be used by PJM to procure additional resource (if needed) or by market participants to adjust their BRA commitments.

Conducting the capacity market on a three-year forward basis roughly matches the minimum lead time needed to bring new capacity resources online and the lead time needed to delay or cancel projects before irreversible major financial commitments have been made. This improves price stability and reliability by providing forward market signals that can help avoid periods of extreme scarcity or excess capacity. It also forces existing resources to compete with a potentially large supply of new resources that can be brought online within three years.

Locational Deliverability Areas ("LDAs). LDAs are subregions of PJM with limited import capability due to transmission constraints. If an LDA is constrained, locational capacity prices will exceed the capacity price in the unconstrained part of PJM. Currently there are 25 LDAs defined in RPM, although, as shown in

Figure **1** and Figure 2 show only eight LDAs currently modeled such that capacity auctions could yield different clearing prices. The LDAs currently modeled in PJM are: the unconstrained Regional Transmission Organization ("RTO"); the Mid-Atlantic Area Council ("MAAC") which contains subzones Eastern MAAC ("EMAAC") and Southwestern MAAC ("SWMAAC"); SWMAAC contains the Potomac Electric Power Company ("PEPCO") subzone, SWMAAC also contains the Baltimore Gas and Electric ("BGE") zone, which is not a constrained LDA by itself; EMAAC contains the Delmarva Power and Light Company ("DPL") South ("DPL South") and Public Service Electric and Gas Company ("PSEG") LDAs; and PSEG contains PSEG North.

Figure 1
Constrained Locational Deliverability Areas in RPM

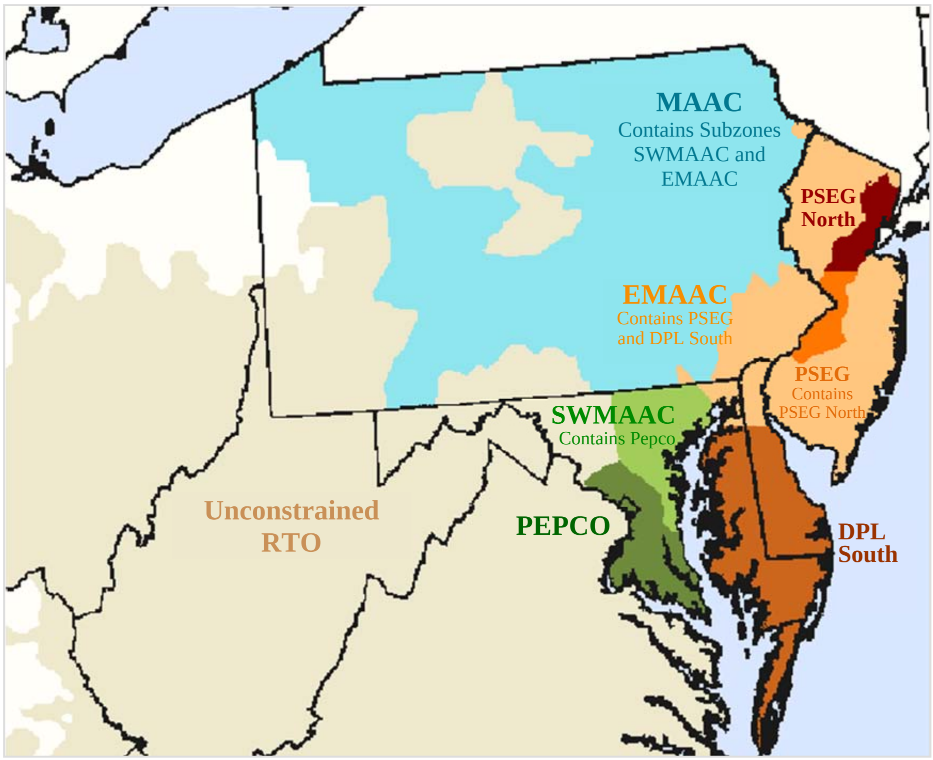
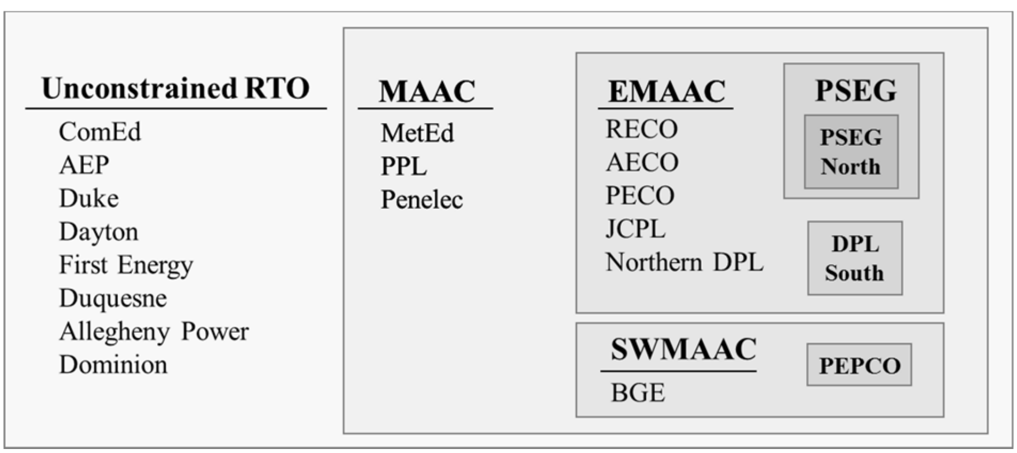


Figure 2
Locational Deliverability Areas and Utility Service Areas



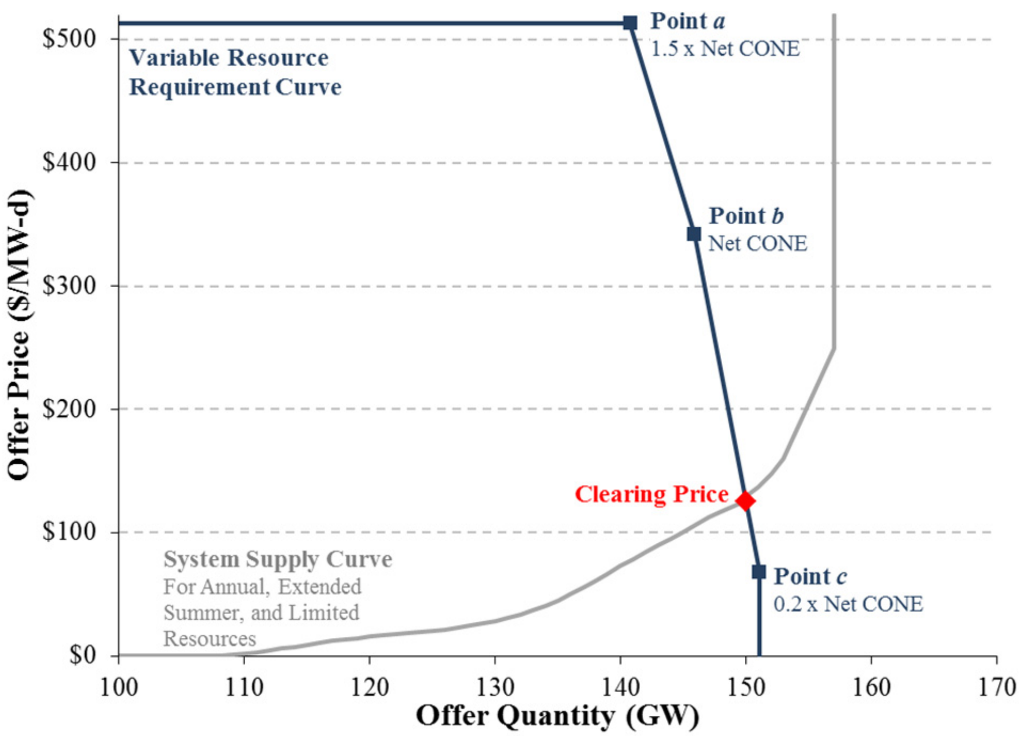
Sources and Notes:
Modeled LDAs are shown as squares with names in bold; other transmission zones are not currently modeled.
LDA definitions and structure from PJM (2011d), pp. 10-11.

Participation by Demand-Side Resources and New Transmission Upgrades. RPM enables participation by demand-side resources and new transmission projects. Capacity provided by these resources is treated equivalently to generating capacity. Eligible transmission projects, called Qualifying Transmission Upgrades ("QTUs"), can participate to increase import capability into a constrained LDA.

Downward Sloping Demand Curve. The VRR curve is anchored at point "b" at a price and quantity that reflects the Net CONE and a reserve margin that is one percentage point above the target reserve margin that satisfy regional and locational reliability standards. Net CONE is determined as the annualized fixed cost of new generating capacity *net* of energy and ancillary service ("E&AS") margins.

The VRR curve is designed to yield auction clearing prices in excess of Net CONE when the amount of cleared capacity falls below the target reserve margin needed to satisfy regional and local reliability requirements. Similarly, capacity prices fall below Net CONE when the amount of cleared capacity exceeds target reserve margins. Figure 3 shows the capacity supply curve, VRR curve, and auction clearing price and quantity for the most recent RPM auction, which procured capacity for the 2014/15 delivery year.

Figure 3
Capacity Supply and Demand in the 2014/15 Base Auction



By definition, this VRR curve yields a capacity price equal to Net CONE at the target reserve margin plus 1 percentage point (point "b"). For lower supply levels, capacity prices increase linearly to reserve margins that are 3 percentage points below target reserve margins, at which point the capacity price is capped at 150% of Net CONE (point "a"). From the price equal to Net CONE at target reserve margins plus 1 percentage point, capacity prices also decline linearly until reserve margins reach target reserves plus 5 percentage points, at which the capacity price is equal to 20% of Net CONE (point "c"). For even higher reserve margins, capacity prices drop to zero.

As was noted in the FERC order approving the RPM design,[6] compared to a system that simply attempts to procure capacity to satisfy a target reserve margin (*i.e.*, a vertical demand curve), the downward-sloping demand curve is designed to provide the following advantages:

- The downward-sloping VRR curve reduces capacity price volatility because capacity prices change gradually as capacity supplies vary over time. The lower volatility due to a sloped demand curve should render capacity investment less risky, thereby encouraging greater investment at a lower cost.

- The sloped demand curve provides a better indication of the incremental and decremental value of capacity at different planning reserve margins. The sloping VRR curve recognizes that incremental capacity above the target reserve margin provides additional reliability benefit, albeit at a declining rate.

- The sloped VRR curve also mitigates the potential exercise of market power by reducing the incentive for suppliers to withhold capacity when aggregate supply is near the target reserve margin. Withholding capacity is less profitable under a sloped demand curve close to the target reserve requirements than under a vertical one because withholding would result in a smaller increase in capacity prices.

Determination and Adjustments of CONE. The value of CONE is estimated as the levelized cost (currently defined in constant nominal dollar terms) that a new entrant needs to recover in power markets—including energy, ancillary service, and the RPM capacity market—to recover its investment costs. The PJM Tariff allows for periodic review and adjustment of the CONE parameter through a combination of index-based adjustment and periodic updates based on engineering cost studies.

Energy and Ancillary Services Revenue Offset. The E&AS offset represents the administratively-estimated net profit that a new entrant with the reference technology earns from the sale of energy and ancillary services. E&AS offsets are used to calculate Net CONE which reflects the amount of annual capacity market revenue that the new entrant needs for profitable entry. Under current RPM rules, E&AS offsets are calculated as a three-year average of estimated historical profits for the reference technology.

Performance Monitoring. The market clearing price is paid to all capacity committed in an auction. However, these payments can be partially, fully, or more than fully offset by performance-based penalties that depend both on the resources' general availability during the delivery year as well as their availability during peak periods when the reliability value of capacity is the greatest. The combination of these payments and penalties is designed to ensure that suppliers have the proper incentives to make their resources available to PJM during reliability events.

Self-Supply and Bilateral Procurement of Capacity. The RPM market design allows LSEs to self-supply resources to meet their capacity obligations either by designating resources they own or purchase bilaterally. Such capacity must be offered into base auctions. The main purpose of the base auctions is to purchase capacity needs not met by self-supplied resources.

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[6] December 2006 RPM Order at ¶¶75-76.

Fixed Resource Requirement. The FRR alternative allows LSEs to opt out of RPM and, instead, meet a fixed capacity obligation. LSEs that choose the FRR option are subject to certain qualification requirements and face restrictions on the amount of capacity they may sell in RPM auctions.

Market Mitigation. Sell offers of existing capacity resources in RPM auctions are subject to mitigation. Offers can be mitigated to a level that reflects each individual unit's going-forward, avoidable costs. Sell offers by planned resources are not subject to offer caps, but may be rejected by the MMU if they are found to be uncompetitive.

Changes to the RPM design since our 2008 RPM Review. Since we reviewed RPM performance in 2008, PJM implemented a number of refinements to the RPM design and related elements, including the following:

- Two new CONE Areas and a revised CONE update process to by using annual adjustments based on the Handy-Whitman cost index with CONE updates based on engineering studies only every three years.

- RPM procurement targets and FRR obligations that can increase or decrease after the BRA based on changes in load forecast prior to the delivery year (previously the BRA Preliminary Obligation was the floor). Reallocation of capacity obligations of individual load zones prior to delivery years based on changes in peak loads since BRA.

- A number of modifications specifying when and how LDAs are modeled in RPM auctions, including (1) a requirement to model all regional LDAs in each auction (2) the increase in the Capacity Emergency Transfer Limits ("CETL")/ Capacity Emergency Transfer Objective ("CETO") threshold for modeling other LDAs from 105% to 115%; (3) revised guidelines to create new LDAs (Manual 14B); and (4) incorporation of planned transmission additions into CETL only when there is a reasonable expectation that the project can be online as anticipated.

- Revisions to RPM Auction designs, including (1) the addition of the 2.5% Short Term Resource Procurement Target; (2) improved structure and expanded scope of incremental auctions; and (3) separate clearing of limited summer, unlimited summer and annual capacity products.

- Reduced performance penalties to 1.2 times the higher of: (1) the auction resource clearing price in which the capacity was originally cleared; and (2) the third incremental auction resource clearing price.

- A streamlined generation interconnection process that allows planned resources to qualify for RPM more quickly.

- Options that allow market participants to combine individual partial-year resources as annual resources.

- Revisions to how demand-response resources are integrated into the RPM design, including (1) the elimination of ILR to encourage DR participation in BRAs; (2) elimination of offer caps for DR resources; (3) the creation of multiple DR products (limited summer, extended summer, and annual); (4) accommodation of energy efficiency ("EE") resources; (5) testing of DR resources.

- Revisions to the minimum offer price rule ("MOPR") to guard against suppression of RPM clearing prices through the addition of uneconomic generating capacity.

A number of other refinements, such as improved validation and verification processes for generation and demand resources, modifications of how capacity cost responsibilities are allocated to load serving entities ("LSEs"), and modifications to the New Entry Pricing Adjustment ("NEPA") that provide certainty that new resources will clear in subsequent auctions.

II. ANALYSIS OF MARKET RESULTS

This section documents and analyzes market results under RPM to date. First, we analyze the outcomes under each of the eight base residual auctions (BRAs) and seven incremental auctions (IAs) that have been conducted since RPM was implemented, starting with the 2007/08 delivery year. For each of these auctions, we report the clearing prices and the quantities of cleared and uncleared offers by resource type and location. We also explain the causes of price changes over time. Next, we document the cumulative changes in committed capacity since RPM's inception through 2014/15, the latest delivery year covered by the most recent BRA. Finally, we examine the quantity of proposed new generating projects that are currently under study in the generation interconnection queue as an indicator of potential new additions beyond those already committed through RPM.

Our analysis of market results demonstrates that sufficient capacity has been procured under RPM to ensure resource adequacy at prices consistent with locational market conditions. While moderate capacity deficits initially occurred in some LDAs due primarily to pre-RPM conditions, the last four BRAs have cleared more than sufficient capacity in each LDA. Since RPM was implemented, a cumulative 28.4 GW of gross committed capacity and 13.1 GW of net committed capacity (in ICAP terms) has been added under RPM, excluding FRR capacity and the addition of new PJM members, FirstEnergy and Duke. All auction results are reported in UCAP terms in Sections II.A and II.B below, while the cumulative capacity changes under RPM are reported in ICAP terms in Section II.C.

A. BASE RESIDUAL AUCTION RESULTS

Most capacity under RPM is procured through the base residual auctions. Base auctions have been conducted for each of the eight delivery years spanning 2007/08 through 2014/15. Each auction is held three years prior to the delivery year, with the exception of the first four delivery years when the BRAs were conducted over a compressed period while transitioning to the full three-year forward procurement period after RPM's implementation. Over the first eight auctions, and excluding additions due to territory expansion, total capacity supplies offered have increased by 16.9 UCAP GW while capacity cleared has increased by 11.5 UCAP GW, with most incremental supplies coming from demand response.

With a few exceptions during the first delivery years of RPM, primarily within LDAs, each auction has procured capacity in excess of the procurement target, but with surplus supply in the unconstrained RTO exceeding the surpluses in the smaller constrained LDAs. Clearing prices have been consistent with these supply-demand fundamentals, producing prices below Net CONE under conditions of excess supply, but above Net CONE in locations of tight supply during the first few delivery years. Prices have also been substantially affected by whether an LDA was modeled as constrained, changes in LDA transmission import limits (CETL), changes in PJM's load forecasts, a substantial growth in demand response, and the EPA's proposed Hazardous Air Pollutant ("HAP") regulation.[7]

1. Resource Adequacy Achieved Through Base Auctions

Cleared quantities relative to target procurement for the RTO and all modeled LDAs are shown in Figure 4. The figure charts cleared capacity relative to the procurement target for each BRA. The black horizontal line at 100% represents the target procurement quantity, with points above indicating procurement above the reliability target, while points below the line indicate procurement below the target. Procurement levels can deviate from the target because RPM is structured to commit higher quantities when offer prices are low and procure lower quantities when offer prices are high.

At the aggregate RTO level, procurement levels exceeded the target in every one of the first eight base residual auctions by 1.2% to 4.7%. These results reflect the surplus supply conditions in the system overall. The RTO-wide surplus dropped between the introduction of RPM (the 2007/08 delivery year) and the 2010/11 delivery year, but then increased again starting in 2011/12 due to factors that included load forecast reductions, the exclusion of Duquesne as load for one year, and a large influx of DR into the auctions (starting with the May 2009 BRA for the 2012/13 delivery year).

Within the LDAs, overall trends in procurement levels have steadily increased relative to reliability targets. While some procurement levels were below reliability targets during the first four delivery years (2007/08 through 2010/11), procurement levels in LDAs universally exceeded reliability targets for the most recent four delivery years (2011/12 through 2014/15). During the first four BRAs, several LDAs including MAAC, EMAAC, SWMAAC, and DPL-South were below the target in some years, with procurement as much as 2.6% below the target for SWMAAC for the 2009/10 delivery year. These deficits reflected the relatively tighter eastern PJM supply conditions that existed at the inception of RPM and, in fact, motivated the need for a locational capacity market. The compressed timing of the initial three auctions also limited the ability of new resources to enter, given the short lead times to delivery. Additionally, DR was not yet widely participating in the forward auctions, opting instead to participate as Interruptible Load for Reliability ("ILR"), which was committed for reliability outside the auctions.[8] In subsequent auctions, conducted a full 3 years before delivery, additional new

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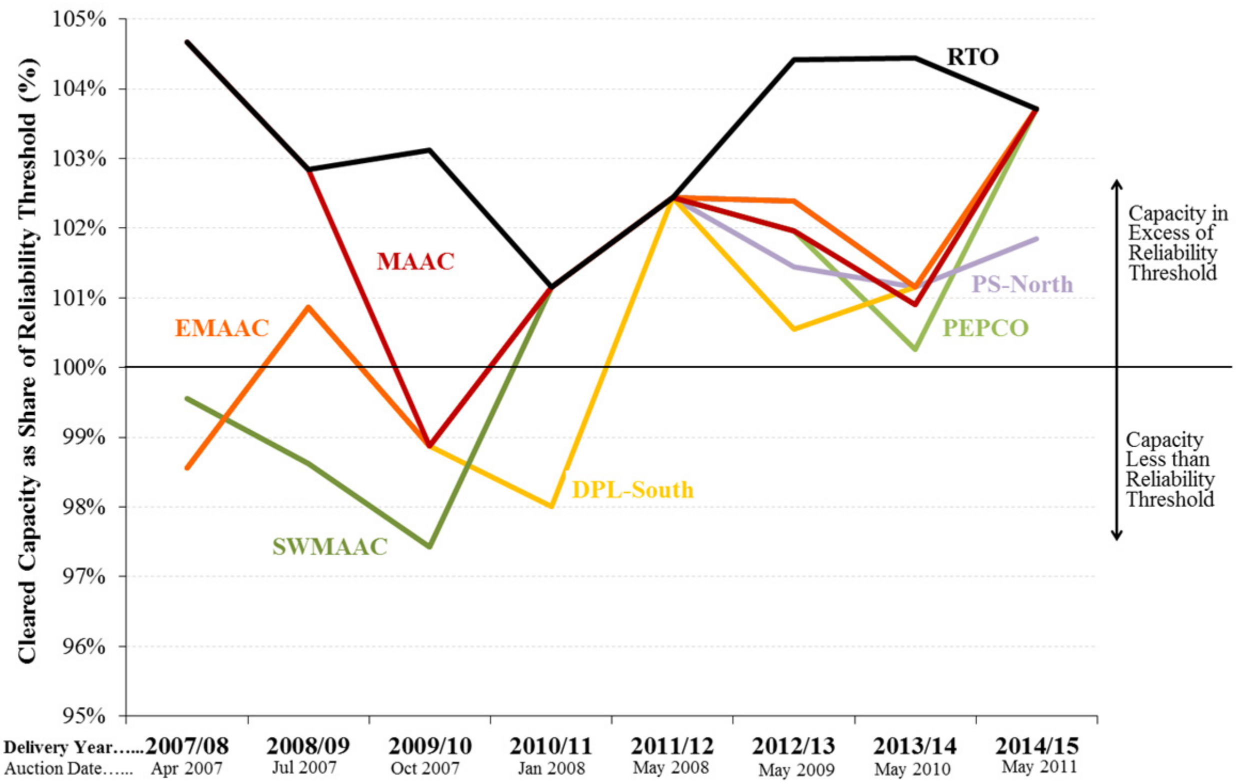
[7] The proposed rule will institute emissions limits for coal- and oil-fired generators for mercury, particulate matter as a proxy for other toxic metals, and hydrochloric acid as a proxy for all toxic acid gases. See EPA (2011a-b).

[8] The first four BRAs under RPM were conducted within one calendar year between April 2007 and January 2008. This means that the 2007/08 BRA was held two months prior to the delivery year, the 2008/09 BRA was held 1 year prior to delivery, the 2009/10 BRA was held 1.5 years prior to delivery, the 2010/11 BRA was held 2.5 years prior to delivery, and all auctions starting with 2011/12 were held 3 years prior to delivery.

capacity resources entered, and the LDA procurement increased to meet or exceed reliability requirements.

Figure 4
Reliability Margins Clearing in Base Residual Auctions



Sources and Notes:
Reliability threshold defined as the reliability requirement less CETL, less forecast ILR or STRPT.
LDAs that did not price separately are reported here at the reliability margin of the parent LDA or RTO level.
From BRA parameters and results, PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011b-c).

2. Market Clearing Prices in Base Residual Auctions

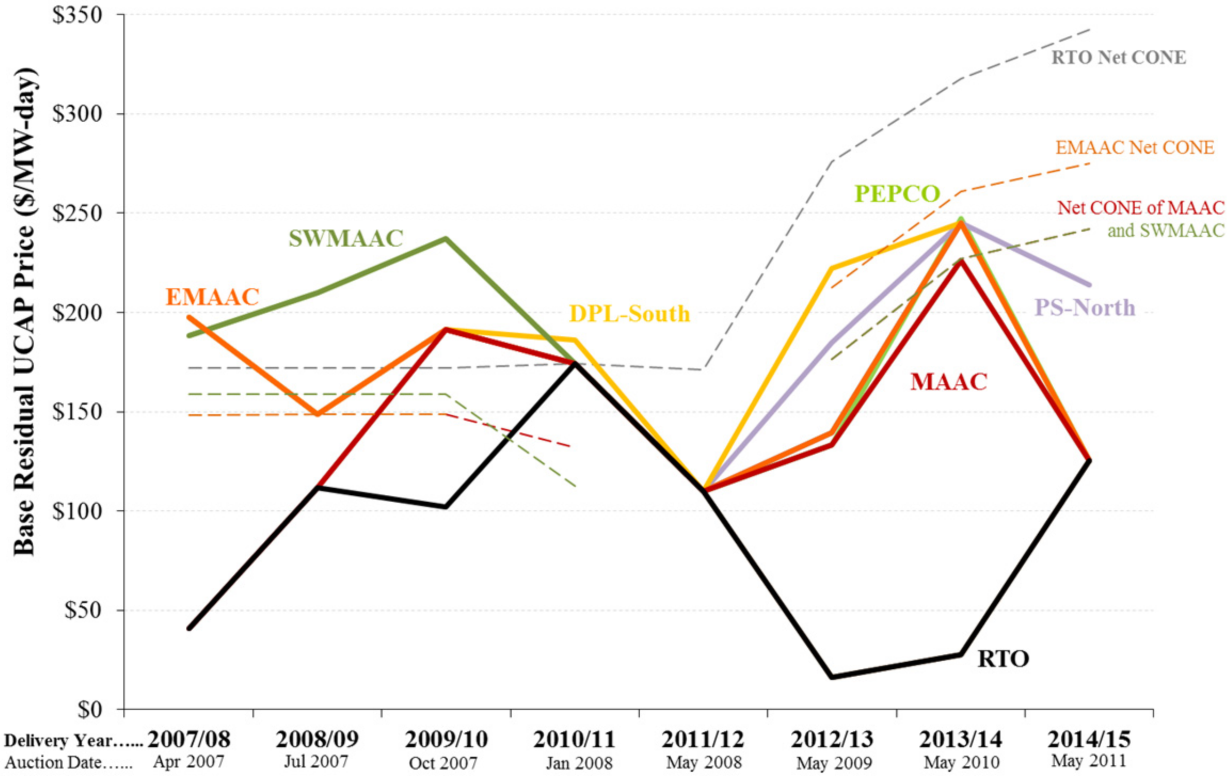
Market prices for capacity can be compared to the Net Cost of Net Entry (Net CONE), representing the fixed cost of a new peaking plant net of operating margins from energy and ancillary service revenues. Net CONE is the capacity price that a developer would need to receive *on average* over the life of its asset to earn an adequate return on invested capital.

In a well-functioning capacity market, capacity prices will be above Net CONE during shortage conditions when new capacity is needed and below Net CONE during surplus conditions when no new capacity is needed. Such market prices will provide sufficient incentives to attract and retain capacity when new supplies are needed, encourage cost savings by postponing new development, and allow economic retirements when supplies are more than sufficient. This is the desirable pattern that has been observed in RPM auctions, as shown in Figure 5.

Figure 5 and Table 1 summarize RTO and LDA clearing prices for each base residual auction conducted to date. Figure 5 also shows Net CONE for each area in dashed lines. Although the administratively-determined Net CONE calculation may deviate from the true Net CONE faced by suppliers (as discussed in Section V), it is still a meaningful benchmark for interpreting auction results. The comparison of Figure 5 to Figure 4 confirms that prices have been above Net CONE under conditions of capacity scarcity and below Net CONE under conditions of capacity surplus.

Prices in the unconstrained RTO have been far below Net CONE in most years, reflecting significant excess capacity and the availability of low-cost resources that obviated the need for new generation capacity. Within the LDAs, several of the initial auctions produced prices above Net CONE—in MAAC, EMAAC, SWMAAC, and DPL-South—consistent with the initial resource adequacy deficiencies. In more recent auctions for delivery years 2011/12 through 2014/15, capacity supply conditions have reduced prices in these LDAs to levels below Net CONE. These observations are not surprising given that RPM is constructed to produce this result, with a sloping VRR curve that procures less capacity at higher prices during shortage conditions and more capacity at a lower price during surplus conditions.[9]

Figure 5
Resource Clearing Prices in Base Residual Auctions



Sources and Notes:
Administrative Net CONE shown only for the years when it was calculated for each modeled LDA.
Year 2014/15 price shown reflects the system clearing price applicable for Limited Summer resources.
From PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011b-c).

9 There are some exceptions to this outcome caused by the 1% quantity adjustment to point b on the VRR curve, which causes prices to clear slightly above Net CONE under slight surplus procurement conditions of less than (1+IRM+1%)/(1+IRM) This occurred in DPL-South in 2012/13 and in PEPCO in 2013/14. For the formula used to calculate VRR curve points, see PJM (2011d), p. 19.

Table 1
Base Residual Auction Clearing Prices

Year	RTO ($/MW-d)	MAAC ($/MW-d)	EMAAC ($/MW-d)	SWMAAC ($/MW-d)	DPL-S ($/MW-d)	PSEG ($/MW-d)	PS-N ($/MW-d)	PEPCO ($/MW-d)	Resource Type
2007/08	$40.80	--	$197.67	$188.54	--	--	--	--	n/a
2008/09	$111.92	--	$148.80	$210.11	--	--	--	--	n/a
2009/10	$102.04	$191.32	$191.30	$237.33	--	--	--	--	n/a
2010/11	$174.29	$174.30	--	$174.30	$186.12	--	--	--	n/a
2011/12	$110.00	--	--	--	--	--	--	--	n/a
2012/13	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	--	n/a
2013/14	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	n/a
2014/15	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	*Limited Summer*
	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	*Extended Summer and Annual*

Sources and Notes:
From BRA results, PJM (2007a, 2008a-c, 2009a, 2009e, 2010b, 2011c).
Prices are reported only for years in which each LDA was modeled under RPM.
MAAC + APS price is listed under MAAC for the 2009/10 delivery year.

In addition to these overall supply and demand conditions, many other factors influenced prices, including the significant growth of DR supply, the economic downturn, new environmental regulations, transmission changes, changes to the RPM market design, and changes in RPM administrative parameters. These factors introduced substantial volatility into the auction prices, with large price changes from one year to the next. We analyzed the major drivers of all price changes for the first eight base auctions by examining offer data, supply curves, administrative planning parameters, and RPM rule changes.

Table 2 summarizes our findings. As documented, supply-side factors explain some of the major changes in base auction prices. Most notably, the costs of meeting EPA's new environmental rules contributed to a price increase of $98/MW-day for the 2014/15 delivery year relative to the previous year.[10] On the other hand, increased DR penetration exerted substantial downward pressure on prices, with the largest impact seen starting with the 2012/13 delivery year, when 8,200 MW of demand resources were first incorporated into the auction, contributing to a $94/MW-day RTO-level price drop relative to the previous year.[11] Modeling multiple demand resource products for the first time in 2014/15 also resulted in a modest price separation of up to $11/MW-day, recognizing the somewhat higher value of Extended Summer and Annual resources. Increases in the supply of other types of resources also contributed to maintaining capacity prices below Net CONE. These other sources of supplies include substantial uprates to existing power plants, increased imports, and reduced exports, as discussed further in Section II.C.

[10] See discussion in Section II.A.3, and EPA (2011a-b).

[11] See Section II.A.3 and PJM (2011d), sections 4.3.5 and 9.3.6.

On the demand side, PJM's peak load forecast is a key driver of PJM prices because it is the primary determinant of the target procurement quantity. Load forecast decreases of 1.7% and 2.8% for the 2012/13 and 2014/15 delivery years (relative to the prior year's peak load forecast for the same delivery years) contributed to price reductions in those years, although in neither case was it the most important driver.[12,13] The initial reduction in load forecasts was caused by the economic downturn. The second reduction in load forecasts was caused primarily by changes in forecasting model coefficients due to revisions in historical economic growth rate data used to estimate those coefficients.[14] For the 2011/12 delivery year, the exclusion of 2.9 GW of peak load from Duquesne contributed to a small reduction in price for one year when the transmission owner had planned to withdraw from PJM.[15] Increases in the administratively-determined Net CONE value also tended to increase prices over time by shifting up the VRR curve, although this trend has not had a large impact in any one year.

Finally, locational price differentials were driven partly by locational differences in supply and demand conditions, with excess capacity in the unconstrained RTO and no (or less) excess supply in the eastern LDAs as discussed above and in in Sections II.C. Additionally, major price changes were caused by whether or not an LDA was modeled as being constrained and how much capacity (CETL) could be imported into the LDA. Prior to a rule change for the 2012/13 delivery year, fewer LDAs were modeled, resulting in a lack of locational price separation during some years that would have price-separated under current rules.[16] For example, the MAAC LDA was not modeled for 2007/08 and 2008/09 and no LDAs were modeled for 2011/12. The administratively-determined Capacity Emergency Transfer Limit ("CETL"), which represents the maximum capacity import capability for each LDA, also significantly affected prices. In particular, CETL decreases for the 2013/14 delivery year were a major cause of high prices in the LDAs, while CETL increases for 2008/09 and 2014/15 were a major cause of price reductions.[17]

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[12] For 2012/13, the most important price-depressing factor was the integration of a large amount of demand resources. For 2014/15, a CETL increase and load forecast reduction both contributed to a price decrease in the LDAs; in the RTO, the price-increasing impact of EPA HAP regulations overwhelmed the price reduction effect of reduced load forecasts.

[13] Reported load forecast reductions represent summer coincident peak load forecasts including Duquesne, but excluding ATSI and DEOK. The RTO summer coincident peak load forecast for the 2012/13 delivery year dropped from 147,183 to 144,613 MW between the forecasts prepared in 2008 and 2009; the 2014/15 delivery year forecast dropped from 149,572 MW to 145,404 MW between the forecasts prepared in 2010 and 2011. See PJM (2008d), p. 46; (2009f), p. 50; (2010e), p. 53; (2011g), p. 54.

[14] These economic growth rates were revised by the Bureau of Economic Analysis. Confirmed via personal communication with PJM staff. , See Section VI.B for a more detailed discussion of load forecasting.

[15] See PJM (2009g), p. 1.

[16] Prior to the auction for the 2012/13 delivery year, LDAs were modeled only if their Capacity Emergency Transfer Objective ("CETO") was ≤ 1.05 CETL. Starting with the 2012/13 delivery year more LDAs were modeled, including: (1) MAAC, SWMAAC, and EMAAC which will always be modeled; (2) LDAs with CETO ≤ 1.15 CETL; (3) LDAs that have price separated in any of the three previous BRAs; and (4) any LDAs that PJM expects may price separate. See PJM (2011d), pp. 11-12.

[17] See Section VI.A for further discussion of CETL uncertainty and recommended mitigation measures.

Table 2
Summary of Major BRA Price Shifts and Causes

Year	Location	Causes of Major Price Changes from Previous Year
2007/08	*RTO* -	Price of $41/MW-day 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-day increase caused by relaxed EMAAC transmission constraint, modest demand growth, and a steep supply curve.
	EMAAC -	$49/MW-day drop caused by 2,085 MW CETL increase.
2009/10	*MAAC+APS* -	LDA is first modeled with prices $89/MW-day above the RTO. If MAAC had been modeled in earlier years, it likely would have had similarly high or higher prices.
	SWMAAC -	Clears slightly 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 a steep supply curve, cause RTO prices to increase by $72/MW-day.
	SWMAAC -	63/MW-day 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-day 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-day in MAAC and SWMAAC and by $205/MW-day in EMAAC.
2014/15	*RTO* -	Prices increase by $98/MW-day 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.
	PSEG-North -	Price drop of $31/MW-day is not as substantial as in other LDAs, and is limited by transmission constraints, which are near their historical levels.
	Extended Summer and Annual -	Resource types are modeled separately for the first time, leading to an $11/MW-day price premium for extended summer and annual resources in LDAs and a smaller premium less than $1/MW-day in the unconstrained RTO.

Sources and Notes:
Causes of price changes determined from analysis of auction bid data, supply curves, demand curves, and parameters.
From BRA parameters, results, and bid data, PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011a-c).

3. Resources Offered and Cleared in the Base Auctions

a. Aggregate Results for the Entire PJM RTO

The total amount of capacity offered in the RTO has increased substantially since the start of RPM, as summarized in Table 3. The table reports total quantities of unforced capacity (UCAP) offered, cleared, and uncleared in the eight base auctions conducted to date for the entire RTO. The tables are non-cumulative with respect to the identification of new generation offers, in that any new generation that clears one BRA is reported as existing generation for all subsequent BRAs.[18] Total offers have increased by 29.6 GW (from 131 to 160 GW) while total capacity cleared has increased by 20.6 GW (from 129 to 150 GW). However, nearly half of that increase is due to PJM's expansion that integrated FirstEnergy (through its subsidiary American Transmission Systems, Inc. or "ATSI") into the BRA starting with the 2013/14 delivery year.[19] Duke Energy Ohio/Kentucky ("DEOK") also began its integration into RPM starting with the 2014/15 BRA, but so far has had little impact on auction clearing quantities.[20]

For the RTO (excluding ATSI and DEOK), capacity offers increased by 16.9 GW while capacity cleared increased by 11.5 GW. Large increases came from new DR and energy efficiency (EE) resources. Cleared quantities of DR and EE increased from just 0.1 GW at the start of RPM to 13.9 GW for the 2014/15 delivery year. DR and EE now amount to 9.9% of total cleared supplies. Cleared imports also increased from 1.6 to 4.0 GW or to 2.9% of cleared supplies.[21]

For PJM-internal generation supplies (including both new and existing resources), total offered quantities decreased by 0.7 GW while total cleared quantities decreased by 4.7 GW. These reductions were almost entirely caused in response to EPA's HAP regulation, which will substantially tighten emissions standards on mercury, other toxic metals, and acid gases. In anticipation of this regulation and the need for environmental upgrades by 2015 or 2016, a large number of coal units of FRR entities were excused from offering into the 2014/15 auction or failed to clear in the BRA after offering at higher levels reflecting the costs of upgrades (and some cleared).[22]

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18 Also note that the same unit may be listed as new capacity under more than one BRA if the new unit failed to clear the first time it was offered and was offered later in a subsequent BRA. This approach to summarizing new generation is consistent with the definition of new generation as used for market monitoring and mitigation purposes, see PJM (2011d), p. 65. Section II.C contains a cumulative account of capacity additions and reductions over time.

19 ATSI was integrated into the PJM energy market on June 1, 2011, but as a transitional measure for resource adequacy purposes it was not fully integrated into RPM auctions until the 2013/14 delivery year. For the 2011/12 and 2012/13 delivery years, resource adequacy in the zone was assured through transitional FRR plans for which capacity was procured in separate integration auctions. Only small amounts of capacity from ATSI were offered into the BRA. See PJM (2010c) and (2011e).

20 See PJM (2010d), pp. 25-26.

21 These are gross imports cleared in the base auctions without considering exports.

22 The exact date that most generators will be required to either shut down or operate with additional controls is not yet determined. The EPA is required under consent decree to issue a final rulemaking by November 16, 2011, after which generators will have three years to comply, with the possibility of an additional year's extension for compliance if they can show that the additional time is needed to install

Continued on next page

Table 3
RTO Summary of BRA Offered and Cleared Quantities
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Total RTO								
Offered	130,844	131,881	133,551	133,093	137,720	145,373	160,898	160,486
Cleared	129,409	129,598	132,232	132,190	132,222	136,144	152,743	149,975
Uncleared	1,435	2,283	1,319	902	5,499	9,230	8,155	10,512
RTO Excluding ATSI and DEOK								
Offered	**130,844**	**131,881**	**133,551**	**133,093**	**137,057**	**145,373**	**147,563**	**147,724**
Existing Internal Generation	129,080	129,408	130,467	129,984	131,013	131,095	131,205	127,418
Existing Imported Generation	1,621	1,667	1,708	1,734	1,750	2,336	3,254	4,031
New Generation	16	89	439	407	2,642	1,442	783	1,016
Demand Response	128	716	937	968	1,652	9,848	11,568	14,430
Energy Efficiency	-	-	-	-	-	653	754	829
Cleared	**129,409**	**129,598**	**132,232**	**132,190**	**132,222**	**136,144**	**142,047**	**140,957**
Existing Internal Generation	127,645	127,346	129,370	129,237	126,964	125,347	128,461	122,603
Existing Imported Generation	1,621	1,626	1,669	1,726	1,748	2,336	3,254	4,031
New Generation	16	89	300	288	2,144	845	769	395
Demand Response	128	536	893	939	1,365	7,047	8,888	13,108
Energy Efficiency	-	-	-	-	-	569	676	819
Uncleared	**1,435**	**2,283**	**1,319**	**902**	**4,836**	**9,230**	**5,516**	**6,767**
Existing Internal Generation	1,434	2,062	1,098	747	4,049	5,748	2,744	4,815
Existing Imported Generation	0	41	39	8	2	-	-	-
New Generation	-	-	139	119	497	598	14	621
Demand Response	-	180	44	29	288	2,800	2,680	1,322
Energy Efficiency	-	-	-	-	-	84	77	10

Sources and Notes:
Calculated from BRA bid data, PJM (2011a).
New generation includes newly build internal and imported generation that has not cleared any previous auction.
Uprates are treated as existing generation.

It is important to note that every auction attracted more offers than were needed, resulting in some capacity offers not clearing. The uncleared capacity *could* have been procured at higher prices if market conditions were tighter and the capacity was needed. The amount of uncleared capacity was quite low in the initial auctions but has been between 3.7% and 6.8% of cleared supplies in the most recent four BRAs. The increase in uncleared capacity coincided with the first year of full three-year forward procurement and exclusion of Duquesne load in 2011/12 (which reduced demand) and the full integration of demand resources into RPM auctions starting in 2012/13.[23] It is also important to evaluate the availability of cleared and uncleared offers for new generation supplies that have been attracted into the auctions. Offers for new generation ranged from 407 MW to 2,642 MW in each auction starting with 2009/10. Of the total 6,834

Continued from previous page
controls, see EPA (2011b), pp. 24986, 25054. Auction impacts from analysis of 2014/15 FRR-excused and BRA biding data as well as PJM's supplemental 2014/15 BRA report, PJM (2011a) and (2011f).

23 Duquesne's reliability requirement of approximately 3 GW was excluded from the BRA in 2011/12, while supply of approximately the same amount was retained and offered in the BRA, see Monitoring Analytics (2008), pp. 10-12. Prior to the 2012/13 delivery year, demand-side resources could certify as ILR immediately prior to the delivery period and receive payments based on auction clearing prices. Starting with 2012/13, all demand-side resources must be committed under an RPM auction or through a bilateral replacement transaction to receive capacity payments, see PJM (2011d), sections 4.3.5 and 9.3.6.

MW of new generation offered into all base auctions conducted to date, 4,847 MW or 71% have cleared.[24]

b. Resources Offered and Cleared within the LDAs

Some stakeholders raised concerns that the RPM auctions are not attracting new resources to ensure reliability within the LDAs, particularly the smaller LDAs. Our analysis of the data shows that is not the case. RPM auctions attracted offers and cleared adequate resources even in the smaller LDAs, except in some of the earlier auctions as discussed earlier and shown in Table 4. Table 4 summarizes the quantity of cleared and uncleared capacity by LDA for all currently modeled LDAs. Note, however, that previous BRAs did not model the same set of LDAs.

Within MAAC, which is the largest of the LDAs and contains all of the smaller LDAs, cleared supply and uncleared potential supply have been robust.

- Penetration of demand-side resources has been higher in MAAC than in the greater RTO, having increased from 0.1% to 11.1% of total cleared resources under RPM.
- Internal generation supplies in MAAC have been relatively constant over the first eight auctions (while internal generation in the unconstrained RTO decreased). Offered generation in MAAC has increased by 1,297 MW, although the total amount cleared generation has decreased by 671 MW or 1% of cleared resources. Unlike the greater RTO, the MAAC region has been relatively less affected by the proposed EPA regulation. Between the auctions for the 2013/14 and 2014/15 delivery years, MAAC had a 1,877 MW or 3.0% decrease in cleared generation (compared to 4.8% in the RTO overall).
- In addition to the resources that cleared in MAAC, another 0.7% to 6.5% of uncleared offers were available that could have been procured at higher prices had they been needed for reliability. Offers for new generation in MAAC have also been substantial, at 3,512 MW of BRA offers, of which 1,798 MW or 51% have cleared. These offers ranged from 110 MW to 1,038 MW in each year since 2009/10. In the smaller LDAs, the changes in supplies offered and cleared have been similar to MAAC overall although varying by location. In particular, penetration of DR and EE has been high in most LDAs, and by 2014/15 these resources contributed a large fraction of cleared internal BRA supply, ranging from 8.9% for EMAAC to 21.5% in SWMAAC.[25]

Most LDAs, even the smallest LDAs, had substantial quantities of uncleared offers for additional capacity that could have been procured at a higher price had they been needed for reliability. In some years, the smallest LDAs—including PEPCO, PSEG, PSEG-North, and DPL-South—did not have any uncleared offers, but almost all of these events occurred in the initial auctions when

[24] Note that in some cases the uncleared offers may represent the same unit that failed to clear and subsequently re-offered. However, cleared MW as reported here would in no cases represent the same unit twice as once the unit clears in one RPM auction it is no longer considered a new unit. Cleared or uncleared offers for new capacity in the incremental auctions are not reported in this section of the report.

[25] This does not mean DR and EE represent the same large fraction of total resources available to these LDAs as the number does not account for the capacity resources available through import capability in each location.

the regions were not deemed constrained and were not modeled in RPM.[26] Among modeled LDAs, the only BRA showing no uncleared capacity was in DPL-South in 2013/14, a year in which the cleared capacity had already exceeded the procurement target.[27] We observed in none of the LDAs any potentially concerning pattern of persistently low offer quantities, and it appears that substantially higher quantities of supply, if needed, could have been procured in every LDA at higher prices.

New generation offers have been unevenly distributed, although the data is difficult to interpret in the smallest LDAs, including DPL-South, where a single new plant would be sufficient to meet load growth for a decade.[28]

- EMAAC and its subregions—PSEG, PSEG-North, and DPL-South—have all attracted substantial offers for new generation equivalent to between 8% and 31% of total cleared internal resources within these LDAs. Just over half of these offers cleared due to relatively low prices compared to the cost of new entry and sufficient supply, as discussed earlier.
- In SWMAAC, lower quantities of new capacity were offered in the BRAs, but still equivalent to 4.2% of cleared resources, and almost none of this capacity has cleared.
- The PEPCO subregion has attracted only a negligible quantity of offers for new generation capacity to date. This lack of offers for new generation in PEPCO is a potential concern that may be caused by higher development costs and siting challenges. However, the lack of offers likely is also related to the relatively smaller size of the LDA and developers' understanding that the subregion already has sufficient supply, including from high levels of new demand response, reductions in load forecast, and increases in import capability.[29]

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[26] The history of which LDAs were modeled in which year can be seen in

Table **1**, which indicates unmodeled LDAs as dashes.

[27] As seen in Figure 4.

[28] Based on 2,369 MW projected DPL-South peak load in 2014 and 2,637 MW projected peak load in 2024, assuming that DPL-South peak load grows at the same rate as DPL overall. The 268 MW of load growth may translate into a 341 MW increase in the UCAP LDA reliability requirement if it increases proportionally. This increase is smaller than the approximate 650 UCAP MW that may be contributed by a new combined cycle generator as indicated by three recent projects proposed in New Jersey. See PJM (2011b) and (2011g), p. 54; Levitan (2011), p. 2.

[29] For example, between the 2013/14 and 2014/15 BRAs, the need for internal PEPCO resources was reduced from 4,959 to 3,345 UCAP MW or by 33%. Contributing factors to this change were a 491 MW reduction in the reliability requirement and a 1,123 MW increase in CETL. See PJM (2010a, 2011b).

Table 4
LDA Summary of BRA Offered and Cleared
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
MAAC								
Cleared	**60,476**	**60,707**	**63,010**	**63,328**	**61,603**	**65,465**	**67,640**	**67,176**
Existing Generation	60,395	60,190	62,158	62,399	60,018	60,299	61,061	59,487
New Generation	16	40	110	21	540	262	556	253
DR and EE	66	478	743	908	1,045	4,904	6,023	7,436
Uncleared	**557**	**1,404**	**432**	**502**	**3,979**	**2,830**	**698**	**3,709**
Existing Generation	557	1,224	427	355	3,325	2,054	684	1,904
New Generation	-	-	-	119	497	463	14	621
DR and EE	-	180	6	29	156	312	-	1,185
EMAAC								
Cleared	**30,782**	**30,214**	**31,622**	**30,787**	**29,365**	**31,080**	**32,835**	**32,554**
Existing Generation	30,722	30,045	31,157	30,474	28,598	29,260	29,856	29,592
New Generation	16	-	93	6	535	162	494	74
DR and EE	45	169	372	306	231	1,658	2,485	2,888
Uncleared	**29**	**1,148**	**34**	**431**	**2,670**	**1,902**	**172**	**1,966**
Existing Generation	29	973	29	300	2,317	1,526	158	741
New Generation	-	-	-	119	277	223	14	621
DR and EE	-	175	4	12	76	153	-	604
SWMAAC								
Cleared	**10,201**	**10,621**	**9,915**	**10,873**	**10,780**	**11,595**	**11,242**	**11,124**
Existing Generation	10,182	10,312	9,558	10,354	10,039	9,661	9,480	8,726
New Generation	-	-	-	-	-	-	2	3
DR and EE	20	309	356	519	741	1,933	1,760	2,396
Uncleared	**-**	**5**	**397**	**55**	**871**	**801**	**526**	**1,334**
Existing Generation	-	-	397	55	612	477	526	1,093
New Generation	-	-	-	-	221	240	-	-
DR and EE	-	5	-	-	39	85	-	240
PSEG								
Cleared	**6,734**	**6,734**	**6,957**	**6,938**	**6,729**	**7,194**	**8,019**	**7,583**
Generation	6,734	6,681	6,856	6,862	6,699	6,731	6,893	6,614
DR and EE	-	52	101	75	31	463	1,127	969
Uncleared	**-**	**150**	**-**	**282**	**674**	**237**	**14**	**601**
Generation	-	102	-	278	655	223	14	423
DR and EE	-	48	-	4	19	14	-	178
PEPCO								
Cleared	**5,019**	**5,125**	**4,686**	**5,498**	**5,664**	**5,357**	**4,792**	**5,615**
Generation	5,014	5,093	4,621	5,464	5,519	4,840	4,209	4,679
DR and EE	5	32	65	33	145	517	583	936
Uncleared	**-**	**2**	**378**	**-**	**6**	**24**	**497**	**261**
Generation	-	-	378	-	-	-	497	131
DR and EE	-	2	-	-	6	24	-	130
PSEG-North								
Cleared	**3,737**	**3,734**	**3,767**	**3,672**	**3,640**	**3,550**	**4,159**	**3,818**
Generation	3,737	3,734	3,767	3,672	3,640	3,453	3,631	3,374
DR and EE	-	-	-	-	-	97	528	443
Uncleared	**-**	**22**	**-**	**199**	**369**	**223**	**14**	**352**
Generation	-	22	-	199	369	223	14	299
DR and EE	-	-	-	-	-	-	-	53
DPL-South								
Cleared	**1,583**	**1,587**	**1,587**	**1,520**	**1,454**	**1,323**	**1,612**	**1,439**
Generation	1,575	1,587	1,587	1,505	1,428	1,177	1,465	1,213
DR and EE	8	-	-	15	26	146	148	226
Uncleared	**-**	**-**	**-**	**26**	**32**	**257**	**-**	**161**
Generation	-	-	-	26	32	257	-	120
DR and EE	-	-	-	1	-	-	-	41

Sources and Notes:

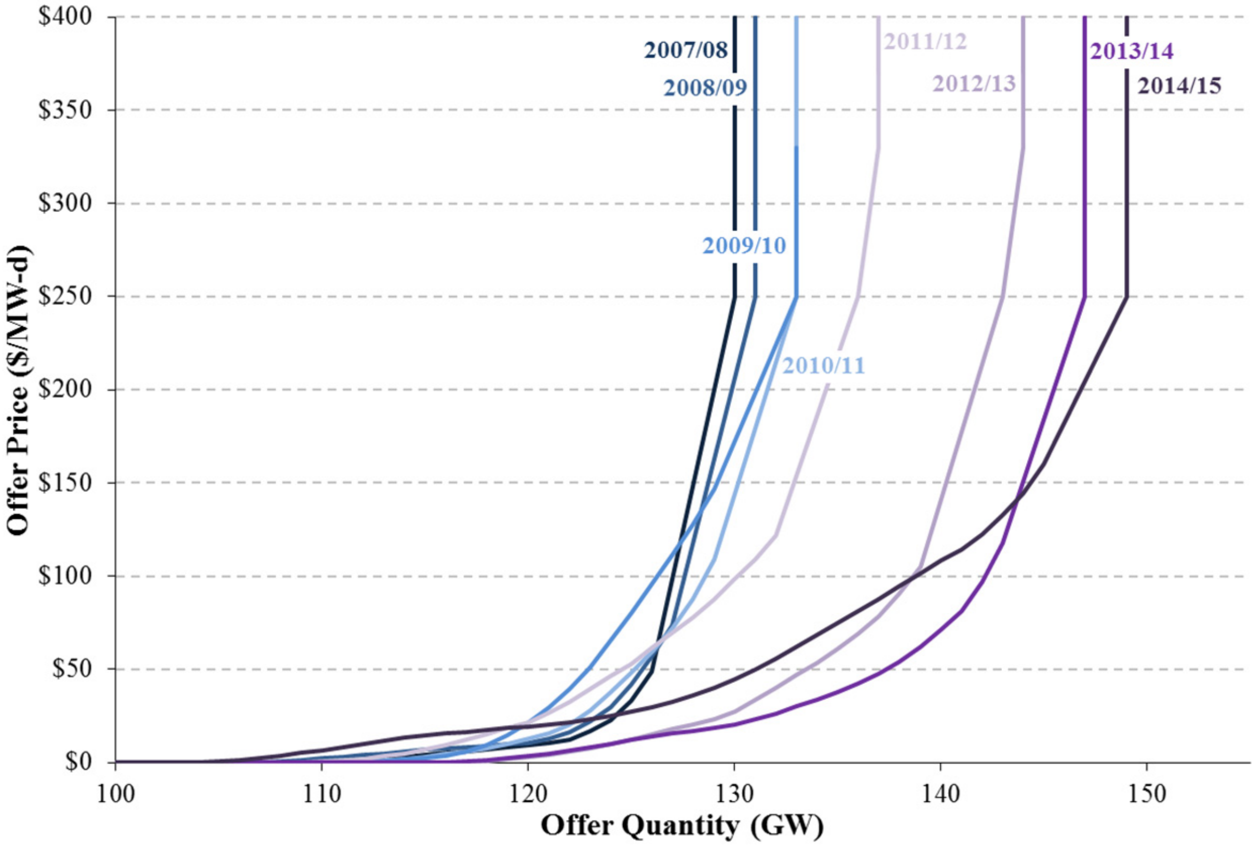
Calculated from BRA bid data supplied by PJM (2011a). Uprates are treated as existing generation.
New and existing generation are aggregated in the smaller LDAs to avoid revealing market-sensitive data.

4. BRA Supply Curves

The previous section described the quantities of resources offered and cleared in the auctions, but did not address the prices at which suppliers offered their resources. In fact, offers from many existing and new resources have changed substantially over time, affecting supply curve shapes and thus auction prices and quantities cleared. This subsection analyzes the shapes of the supply curves and the changes in market rules and fundamentals that have caused them.

Our analysis is based primarily on the mitigated supply curves in each BRA conducted to date, although we have also reviewed the individual resource offers and report observations at an aggregate level. Figure 6 shows the (smoothed) mitigated supply curves offered into the BRA for the delivery years 2007/08 through 2014/15, excluding capacity from ATSI and DEOK to make the curves comparable. The 2014/15 supply curve represents the total system supply of all newly-introduced resource types.[30]

Figure 6
BRA Supply Curves Excluding ATSI and DEOK



Sources and Notes:
Curves exclude supply from ATSI and DEOK zones. Smoothed to mask confidential market data.
From PJM supplier bidding data, PJM (2011a).

30 The curve includes all Annual, Extended Summer, and Limited resources, but does not double-count capacity that submitted linked offers for multiple product types.

Our primary observations, which we explain in greater detail below, are as follows:

- *Supply curves with decreasing slopes through 2011/12*: Overall, the BRA offer curves have become progressively more gradual over time, ascending from zero through many mid-range offers to higher offers. These flatter curves help stabilize auction prices, all else being equal. Offer curves became more gradual as the forward period increased progressively from 2 months to 3 years during the forward-procurement transition from 2007/08 through 2011/12, allowing resource investments to be offered contingent on auction prices.

- *The full integration of DR starting in 2012/13*. Fully integrating DR into the auctions (instead of procuring it outside of the auctions as ILR) significantly expanded the offer curves. At first, existing DR was mitigated to zero. DR was unmitigated starting with the 2013/14 auction, which stretched out the mid-range of the curve.

- *Incorporation of environmental retrofit costs, especially for 2014/15*: the 2014/15 offer curve had the most gradual shape yet, with many coal generators that were previously offering at zero now offering at a range of non-zero prices related to their expected costs of complying with EPA regulation.

- *The introduction of multiple DR products, starting in 2014/15*: as expected, the offers for higher-value Annual and Extended Summer products are less plentiful and occur at higher prices than Limited DR. The Extended Summary and Annual supply curves are very similar to each other.

Supply Curves with Decreasing Slopes through 2011/12. The decreasing slopes of the supply curves for the 2007/08 through 2011/12 delivery years in large part reflect the fact that the base auctions were held with an increasing forward procurement periods of 2 months, 1 year, 1.5 years, 2.5 years, and 3 years to delivery. These first five auctions were held within a single year—between April 2007 and May 2008—as part of the transition period. The comparison of their supply curves shows a progressive change in supply. With each successive auction, substantially more supplies were offered and the supply curve became more gradual. We attribute these changes to the increasing forward period. Without sufficient lead-time to develop new resources, as was the case for the first BRA in 2007/08, supply curves will be steep as nearly all existing resources offer at (or are mitigated to) a price of zero. A forward period of several years will make the supply curve more gradual, as many investment decisions can be made contingent on the auction clearing price. New supplies such as uprates to existing or new generation can offer in to compete with capacity of existing supplies. Further, existing resources that require major capital expenditures to maintain operational can offer at a price commensurate with costs, and then make the upgrade contingent on clearing. Overall, the more gradual supply curve indicates that the three-year forward period has contributed to increased efficiency and competition among resources. It also contributes to greater stability in clearing prices.

The Full Integration of DR Starting in 2012/13. The 2012/13 supply curve shows a large increase in the quantity of offers due to the influx of DR into the auctions. In 2012/13, existing DR suppliers were required to offer into the capacity market at a mitigated offer price of zero.[31]

[31] See FERC (2009), pp. 10-11.

Starting with 2013/14, offer prices for DR were unmitigated and these suppliers offered over a range of prices.[32] The rapid growth of low-cost DR in the last several auctions contributed to lower prices, which has been a cause for concern among generation owners. We expect that the price-reducing effect of DR will not continue indefinitely, as continued DR growth will result in greater curtailment frequencies and more costly DR resources in the future. In fact, we observed that, starting with the auction for the 2013/14 delivery year, DR suppliers offered over a range of prices, which contributed to a substantially more gradual supply curve. These DR offer levels are likely related to opportunity costs of retail customers and expectations regarding future curtailment levels, as well as a range of customer characteristics. We expect that DR offer curves will eventually stabilize, and cleared amounts will increase or decrease with capacity prices, thereby creating more price stability in RPM.

Incorporation of Environmental Retrofit Costs, Especially for 2014/15. The 2014/15 supply curve has fewer offers at zero prices. Many existing generation resources were offered at non-zero levels, mostly due to coal units offering at prices related to their costs of environmental upgrades to meet EPA regulations. While the total system-wide costs of these upgrades are substantial, and installing them all simultaneously will be a challenge, we note that the three-year forward period of RPM has greatly increased the transparency of this process. Because coal units have bid into the capacity market over a range of prices consistent with their expected costs, the forward capacity auction has effectively prioritized the lowest-cost upgrades. Coal units requiring more expensive upgrades, presumably on older and less efficient plants, did not clear and will likely retire, thereby also reducing the current capacity surplus.

The Introduction of Multiple DR Products, Starting in 2014/15. Given the greater capacity obligations of Extended Summer and Annual resources, the supply curves for these resources are at a higher price and have fewer offers available than Limited Resources. There is a large difference in the quantity of Limited and Extended Summer supplies, and it has been suggested that some Limited Summer resources did not have sufficient time to revise their contracts to allow them to offer an Extended Summer product. We also note the possibly surprising fact that the Extended Summer and Annual supply curves are very similar to each other, implying that the large majority of these non-Limited resources may have annual capability. The similarity between the Annual and Extended Summer supply curves also indicates that DR suppliers may not expect substantially more curtailment for Annual resources under current market conditions. In the future, as DR penetration reaches a level sustainable in the long term, we expect that curtailment frequencies will increase and, as a result, may be quite different for Limited, Extended Summer, and Annual DR products. Under those conditions, we would expect a larger discrepancy between the supply curves for the varying obligation levels.

B. INCREMENTAL AUCTION RESULTS

A small portion of capacity is procured through the incremental auctions. No stakeholder group raised concerns about the incremental auctions. However, these auctions play an essential role in RPM's ability to meet resource adequacy requirements efficiently. The incremental auctions are used to procure 2.5% (starting with the 2012/13 delivery year) of the expected total capacity obligation for the delivery year and are used to procure any unexpected needs that emerge

[32] See PJM (2011d), p. 65.

between the BRA and the delivery year. Incremental auctions help short-term resources compete without assuming the risks of three-year forward commitments. They also help reduce the risk of other suppliers assuming forward commitments by providing opportunities to buy (and sell) replacement capacity if needed.

This section explains the timing of incremental auctions, documents rules changes, analyzes offers and buy bids, and reports auction prices. We find that IA prices prior to the auction redesign were consistently below the BRA prices and that the prior IA design created an uneconomic incentive for DR resources to bid just above the BRA price. Results after the auction redesign in 2012/13 show that the new design produces results that are more efficient and consistent with market conditions. However, with only two auctions conducted to date, there is still insufficient evidence to fully evaluate the new IA design. We also find that, while many buy bids in incremental auctions were used to replace existing capacity commitments, a substantial number of low-priced buy bids were also submitted pre-emptively to procure extra capacity that can be used to replace potential future deficiencies.

1. Incremental Auction Mechanics and Redesign in 2012/13

Incremental auctions are held two years, one year, and several months prior to the delivery year.[33] For the first four delivery years of RPM, the IAs were primarily a capacity aftermarket in which suppliers could adjust their capacity commitments for changes to their resource ratings or costs. In these early years, PJM did not procure any net capacity from the first or third IAs for resource adequacy, although a load forecast increase would have triggered a second IA for incremental procurement.[34]

Third incremental auctions have been held for the 2008/09 through 2011/12 delivery years. First IAs have been conducted for 2011/12 and 2012/13. Several early delivery years did not have a full set of IAs due to the compressed forward period when RPM was phased in and because second incremental auctions would only have been held in the case of a load forecast increase.

Starting with the 2012/13 delivery year, a new incremental auction design was implemented. The first, second, and third IAs now have a Short-Term Resource Procurement Target ("STRPT") of 0.5%, 0.5%, and 1.5% respectively. The redesign also fully incorporated DR resources into the capacity auctions instead of awarding auction-based prices to DR certified as Interruptible Load for Reliability (ILR) immediately prior to the delivery year. Additionally, the new incremental auction design includes the uncleared portion of the VRR curve and adjusts the demand for updates in the load forecast and transmission limits in some cases.[35] Suppliers can use these incremental auctions to adjust or replace their capacity obligations.

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[33] Specifically, the first IA is held 20 months prior to delivery, the second IA is held 10 months prior to delivery and the third IA is held 3 months prior to delivery. A conditional IA may also be held if additional capacity is needed due to a delay in a backbone transmission upgrade. See PJM (2011d), pp. 69-72.

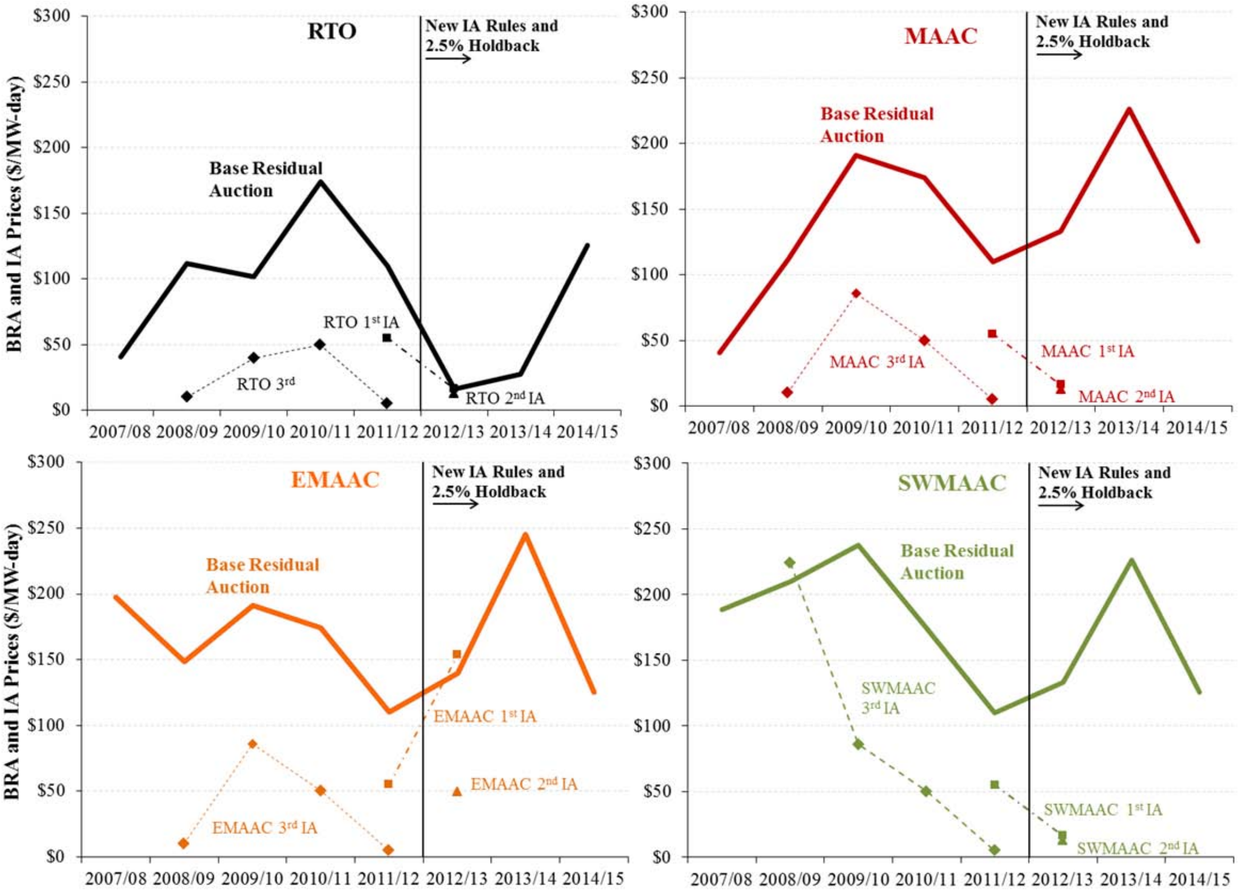
[34] No second IA was ever held for this reason. See *Id.*, p. 72.

[35] See *Id.*, pp. 20-21.

2. Incremental Auction Clearing Prices

Clearing prices in the IAs are summarized in Figure 7 for the RTO and the largest LDAs. (Table 5 shows prices for all locations.) Figure 7 shows BRA prices as a solid line with incremental auction prices shown as dashed lines.

Figure 7
Incremental Auction Clearing Prices



Sources and Notes:

Year 2014/15 BRA clearing prices reflect resource clearing prices without an Annual or Extended Summer price adder.
From BRA and IA results, see PJM (2007a, 2008a-c,e, 2009a,e,h-i, 2010b,f,g, 2011c,g).

As Figure 7 shows, incremental auction prices under the initial design were persistently and substantially below BRA prices—on average $90/MW-day lower in the RTO and on average $115/MW-day lower in MAAC. The only exception occurred in SWMAAC in the third incremental auction for the 2008/09 due to tight supply conditions. Less experience exists to date for the new IA design. However, Figure 7 shows that prices in the first IA for the 2012/13 delivery are very close to BRA prices in the RTO and EMAAC, but much lower than BRA prices in MAAC and SWMAAC.

Table 5
Incremental Auction Clearing Prices

Year	Auction	RTO ($/MW-d)	MAAC ($/MW-d)	EMAAC ($/MW-d)	SWMAAC ($/MW-d)	DPL-S ($/MW-d)	PSEG ($/MW-d)	PS-N ($/MW-d)	PEPCO ($/MW-d)
2007/08	BRA	$40.80	--	$197.67	$188.54	--	--	--	--
2008/09	BRA	$111.92	--	$148.80	$210.11	--	--	--	--
	3rd IA	$10.00	--	$10.00	$223.85	--	--	--	--
2009/10	BRA	$102.04	$191.32	$191.30	$237.33	--	--	--	--
	3rd IA	$40.00	$86.00	$86.00	$86.00	--	--	--	--
2010/11	BRA	$174.29	$174.30	--	$174.30	$186.12	--	--	--
	3rd IA	$50.00	$50.00	--	$50.00	$50.00	--	--	--
2011/12	BRA	$110.00	--	--	--	--	--	--	--
	1st IA	$55.00	--	--	--	--	--	--	--
	3rd IA	$5.00	--	--	--	--	--	--	--
2.5% Holdback Introduced and New Incremental Auction Design is Implemented									
2012/13	BRA	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	--
	1st IA	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	--
	2nd IA	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	--
2013/14	BRA	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14
2014/15	BRA	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47

Sources and Notes:
From BRA and IA results, see PJM (2007a, 2008a-c,e, 2009a,e,h-i, 2010b,f,g, 2011c,g).
Prices are reported only for years in which each LDA was modeled under RPM.
MAAC + APS price is listed under MAAC for delivery Year 2009/10.

To determine the drivers of incremental auction prices and the price changes between the BRA and the IAs, we examined supply and demand offer data for each of these auctions. A detailed explanation of these price drivers is presented in Table 6. Under the new design, prices in MAAC and SWMAAC were much lower than BRA prices because the load forecast for the delivery year decreased in MAAC. The EMAAC price did not decrease despite a reduced load forecast because of a delay of the Susquehanna-Roseland transmission line, which required substantial incremental capacity procurement.[36] Prices in the second IA for 2012/13 were driven by a reduction in the load forecast in most locations, resulting in a small reduction of prices in the RTO, MAAC, and SWMAAC relative to the already low first IA price, and a large $105/MW-day reduction in EMAAC and its sub-LDAs. These price changes under the new IA design are consistent with the changes in capacity requirements experienced during the period between when the BRA and IA were conducted.

Under the prior incremental auction design, IA prices were consistently far below clearing prices in the BRAs. Offer prices and quantities of generation supply were the primary driver of these price reductions. During the incremental auctions for the 2009/10 and 2010/11 delivery years, a substantial amount of capacity uprates offering at low prices contributed lower-priced supply curves in the IAs. In most other IAs, less existing generation capacity was offered than had

36 See PJM (2010h).

previously not cleared in the BRAs, but some of the resources that did not clear in the BRA dropped their offer prices to zero or near zero. This change in offer price behavior for some generators, combined with a reduction in offer quantities, resulted in IA supply curves that were relatively steep in some cases. Resulting IA prices were low, however, because of low demand, which meant that the auctions cleared in the low-priced portion of the supply curves.

In some cases, substantially more DR was offered into the IAs than what went uncleared in the BRA, particularly during the third IA for the 2011/12 delivery year. However, prior to the 2012/13 delivery year, these additional DR supplies had little effect on IA clearing prices as nearly all of these suppliers offered at prices just above the BRA clearing price. The higher-priced DR offers were consistent with incentives under the prior IA design, because suppliers could be certified as ILR immediately prior to the delivery year and receive a capacity payment based on BRA price for that year. Under that structure, DR suppliers had an incentive to bid into the IAs only to possibly capture a price above the BRA price. With the revision of the IA design and the elimination of ILR (and incorporation of these DR supplies into the RPM auctions) for the 2012/13 delivery year, DR suppliers in the both the IAs and BRAs have begun offering significant amounts of supply over a large range of prices.

Market participants' demand bids in the IAs have been for small amounts of capacity at high prices and very high quantities at low prices. In fact, most demand bids submitted at a zero price. The qualitative shape of the demand curve in the first IA is different from the shape in the third IA, with the third IA having higher quantities of demand at higher prices. A relatively higher willingness to pay for replacement capacity in the third IA may be caused by a lack of time to find bilateral replacement transactions between the third IA and the delivery year.

Table 6
Summary of Major Incremental Auction Price Shifts and Causes

Year	Auction	Location	Causes of Major Price Changes Relative to BRA or Previous IA
2008/09	*3rd IA*	*RTO and EMAAC* -	Price decrease of $102/MW-day and $139/MW-day in RTO and EMAAC, respectively, caused by a small increase in supply from existing generation combined with a large reduction in offer prices from existing generation.
		SWMAAC -	SWMAAC IA price clears at the LDA price cap or just $14/MW-day higher than the BRA price, with relatively high prices in both cases caused by tight supply conditions. Only 5 MW of capacity went uncleared in the BRA and 21 MW was offered into the IA.
2009/10	*3rd IA*	*RTO and LDAs* -	Large price reductions of $62-$151/MW-day, depending on the location, are caused by reductions in offer prices from existing generation and generation uprates offered at low or zero prices. Increases in offered DR did not contribute to price reductions because these resources offered at prices above the BRA clearing price.
2010/11	*3rd IA*	*RTO and LDAs* -	Similar to 2009/10 third IA, large price reductions of $124 to $136/MW-day are caused by low offer prices from existing generation and uprates.
2011/12	*1st IA*	*RTO* -	Prices decrease $55/MW-day despite substantially reduced supply relative to uncleared BRA quantities. Demand bids have a large quantity but nearly all demand bids are at or very near zero, causing only a small quantity of low-priced supply offers to clear.
	3rd IA	*RTO* -	Price reduction of $105/MW-day relative to the BRA and $50/MW-day relative to the first IA caused by low generation offer prices relative to the BRA and IA, along with additional low-price DR offers. Despite a substantial increase in DR quantities, the great majority of DR offers were rationally submitted above the BRA clearing price.
2.5% Holdback Introduced and New Incremental Auction Design is Implemented			
2012/13	*1st IA*	*RTO* -	Uncleared portion of the BRA supply curve is very similar to the IA supply curve, with a substantial quantity of offers near the BRA clearing price, resulting in an RTO clearing price identical to the BRA price.
		MAAC and SWMAAC -	Capacity prices decrease by $117/MW-day despite reduced supply relative to BRA uncleared quantity. These reductions were caused primarily by a reduction in peak load forecast in MAAC.
		EMAAC -	Capacity price rises by a modest $14/MW-day in response to a nearly 2,000 MW reduction in CETL caused by a delay in the Susquehanna-Roseland transmission line. This large increase in the required quantity of internal capacity did not result in a large price increase because, similar to the rest of MAAC, existing generators substantially reduced their offer prices relative to the BRA.
	2nd IA	*RTO* -	Capacity prices decreased by $105/MW-day in EMAAC and subzones and by $3/MW-day below the already low first IA prices in all other LDAs. These price reductions were driven by a large reduction in the load forecast.

Sources and Notes:
Causes of price changes determined from analysis of auction bid data, supply curves, demand curves, and parameters.
From BRA parameters, results, and bid data, PJM (2007a-b, 2008a-c,e, 2009a-e,h-i, 2010a-b,f-h, 2011a-c,g).

3. Quantities Offered and Cleared

Table 7 shows the quantities of cleared and uncleared supply offers and demand bids in all incremental auctions conducted to date. BRA uncleared resources are also shown for reference, as a reasonable first assumption would be that many resources failing to clear the BRA might later offer into an IA. Supplier offers are shown separately for new generation, existing generation, and DR and EE. Buyer bids from generation owners are shown separately from bids from DR and EE owners.[37]

Table 7 shows that offered supplies in the third IA exceeded the uncleared BRA capacity by up to 3.7 GW, mostly related to DR that offered only into the third IA (but no earlier auctions) for that delivery year. We do not expect this same result to continue after the 2012/13 incorporation of DR into the auctions, since these resources are now offering significant amounts of capacity into the BRA. For the first and second IAs, offer quantities were less than the BRA uncleared supply by approximately 2 GW and 1 GW, respectively. These reductions in supply for the first and second IAs are mostly related to higher-priced generation that offered into the BRA but did not offer in the IAs. Among new generation resources that failed to clear the BRA, only 30% to 50% have subsequently offered into the IAs. This suggests that some suppliers of new generation or existing generation requiring substantial reinvestment have made their investment decisions contingent on whether they clear in the BRA. If they do not clear in the three-year forward BRA, they likely will not be available for that delivery year.

For existing generation resources, the quantities offered in the IAs for the 2009/10 and 2010/11 delivery years were 1.5 GW and 2.3 GW higher than the quantities uncleared in the BRA. Most of these increases were associated with capacity uprates.[38] For the 2011/12 and 2012/13 delivery years, 2.0 GW and 1.2 GW less existing generation was offered into the first IAs than in the BRA. Most of these reductions are associated with existing resources that have subsequently submitted retirement requests, although some are associated with reduced imports, equivalent demand forced outage rate ("EFORd") changes, derates, or ATSI units that were obligated to offer capacity into the IAs.

For DR and EE resources, the offer levels in the first IAs were 290 MW and 470 MW below the BRA uncleared quantities, while the offer levels in the third IAs were up to 3,980 MW above the BRA uncleared quantities. At first glance, these observations may seem to support the theory that DR and EE have a much greater ability to participate in non-forward auctions, but the data must be interpreted carefully given DR rule changes for the 2012/13 delivery year. Starting with the 2012/13 delivery year, the ILR option was eliminated, so these resources had to clear through auctions.

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[37] Buy bids are submitted by market participants but are not associated with specific resources. For this reason, we have classified buy bids as DR and EE or generation based on the predominant resource holdings of the market participant. The vast majority of market participants offer only generation or only DR and EE.

[38] Specifically, of the increase in supply from existing resources for those two years, approximately 63% was from generation uprates, 18% was from increased imports, 11% was from small generators that did not offer into the BRA, 5% was from EFORd decreases, and 3% was from FRR resources. From PJM (2011a).

Table 7
Summary of Incremental Auction Cleared and Uncleared Offers and Bids
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12		2012/13		2013/14	2014/15
SELL OFFERS										
Base Residual Auction										
Uncleared	**1,435**	**2,283**	**1,319**	**902**	**5,499**		**9,230**		**8,155**	**10,512**
New Generation	-	-	139	119	497		598		14	621
Existing Generation	1,435	2,103	1,136	755	4,714		5,748		4,393	8,454
DR and EE	-	180	44	29	288		2,884		3,748	1,437
Incremental Auctions		*3rd IA*	*3rd IA*	*3rd IA*	*1st IA*	*3rd IA*	*1st IA*	*2nd IA*		
Offered	n/a	**2,339**	**3,256**	**4,554**	**2,843**	**6,538**	**7,086**	**6,448**	n/a	n/a
New Generation	n/a	6	69	30	163	212	179	164	n/a	n/a
Existing Generation	n/a	2,310	2,656	3,073	2,680	2,056	4,492	3,802	n/a	n/a
DR and EE	n/a	23	531	1,452	-	4,270	2,415	2,483	n/a	n/a
Cleared	n/a	**1,032**	**1,798**	**1,846**	**361**	**1,557**	**1,689**	**838**	n/a	n/a
New Generation	n/a	6	19	30	-	175	95	76	n/a	n/a
Existing Generation	n/a	1,003	1,780	1,792	361	844	1,116	525	n/a	n/a
DR and EE	n/a	23	-	24	-	538	478	237	n/a	n/a
Uncleared	n/a	**1,307**	**1,457**	**2,708**	**2,481**	**4,981**	**5,397**	**5,610**	n/a	n/a
New Generation	n/a	-	50	-	163	37	84	87	n/a	n/a
Existing Generation	n/a	1,307	876	1,280	2,319	1,212	3,376	3,277	n/a	n/a
DR and EE	n/a	-	531	1,428	-	3,732	1,937	2,246	n/a	n/a
MARKET PARTICIPANT BUY BIDS										
Incremental Auctions		*3rd IA*	*3rd IA*	*3rd IA*	*1st IA*	*3rd IA*	*1st IA*	*2nd IA*		
Offered	n/a	**2,252**	**2,698**	**5,221**	**11,969**	**8,865**	**9,339**	**11,560**	n/a	n/a
Generation Suppliers	n/a	2,182	2,308	4,789	11,419	8,473	8,581	10,741	n/a	n/a
DR and EE Suppliers	n/a	70	390	432	550	393	758	819	n/a	n/a
Cleared	n/a	**1,032**	**1,798**	**1,846**	**361**	**1,557**	**1,749**	**3,215**	n/a	n/a
Generation Suppliers	n/a	992	1,409	1,414	141	1,164	1,403	2,754	n/a	n/a
DR and EE Suppliers	n/a	40	390	432	220	393	346	460	n/a	n/a
Uncleared	n/a	**1,220**	**899**	**3,375**	**11,607**	**7,308**	**7,590**	**8,345**	n/a	n/a
Generation Suppliers	n/a	1,190	899	3,375	11,278	7,308	7,178	7,987	n/a	n/a
DR and EE Suppliers	n/a	30	-	-	330	-	412	359	n/a	n/a

Sources and Notes:
From PJM supplier bidding data, PJM (2011a).
Buyers are classified as generation or demand suppliers based on the predominant resource type held.

In some cases, after a resource has made a capacity commitment through the BRA, it will have an unforeseen difficulty in meeting this obligation. Reasons might be a construction delay or a major equipment failure or derate. These suppliers can decommit their capacity without penalty as long as they can substitute replacement capacity through self-supply or bilateral transactions or by procuring replacement capacity in the incremental auctions. Market participants may also submit buy bids in the incremental auctions as a hedging measure, even if the procured capacity is not ultimately used to decommit another resource. In the incremental auctions held to date, generation owners have submitted 93% of total buy bids submitted and 80% of bids cleared. DR and EE suppliers have submitted the remaining 7% of buy bids and 20% of bids cleared. Demand in the incremental auctions prior to 2012/13 consisted only of market participants' buy bids, while demand in subsequent IAs also includes a portion related to changes in CETL, reliability requirements (the STRPT), and the incremental portion of the VRR curve.

Among generation owners, it appears that market participants have been using the IAs as a supplement to bilateral and self-supply options for managing their capacity obligations after the

BRA.[39] For generation owners, 79% of their full-year resource replacements have been through self-supply or bilateral transactions; only 66% of the capacity that generators have procured from the IAs has later been used to reduce capacity commitments. Generators have also been very active in substituting capacity for partial years, presumably to avoid penalties.[40] These generators appear to use the IAs as a hedging opportunity by procuring substantial quantities of replacement capacity (as indicated by their high bid quantities), but only if that capacity is available at very low prices (as indicated by their low clearing quantities).

Among DR suppliers, it appears that incremental auctions have represented their primary means of managing capacity obligations after the BRA. For DR suppliers, all capacity procured from the IAs has been used to replace full-year capacity decommitments. This IA capacity has replaced 86% of all decommitments from DR, with the remainder being replaced through self-supply or bilateral transactions.[41] Relative to generation owners, DR suppliers have been much less active in managing partial-year resource replacements.[42]

4. Incremental Auction Supply Curves

We have compared supply curves for each of the IAs to the uncleared portions of the corresponding BRA supply curves. We used this comparison to examine how offer quantities and prices change for supplies that fail to clear the BRA. Figure 8 and Figure 9 below show the (smoothed) mitigated supply curves for the 2011/12 delivery year (prior to the IA redesign and 2.5% holdback) and for 2012/13 delivery year (after the IA redesign and 2.5% holdback).

Prior to the redesign, there were four third IAs and one first IA. One of the most prominent features of the third IA supply curves was the large “shelf” of DR bids submitted at prices just above the BRA price as highlighted in Figure 8. This shelf was caused by inefficient incentives created by the previous ILR mechanism. These resources were allowed to receive a payment based on BRA clearing prices as long as their capacity was certified immediately prior to the delivery.[43] Under that system, demand resources had almost no incentive to offer into the BRA or first and second IAs. Their only incentive to offer in any auction was to capture potentially higher IA prices, which would happen only if the incremental auction cleared at a capacity price

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39 References in this paragraph to bilateral and self-supply replacement transactions refer only to delivery years 2008/09 through 2010/11. The reason for this is that many replacement transactions do not occur until immediately prior to, or even during, the delivery period, even if the replacement capacity was procured earlier. Partial year transactions especially are more common during the delivery year.

40 For example, for 2010/11, generation owners procured 1,414 MW in the third IA, which were used in 1,014 MW of full-year resource decommitments and another 1,507 MW of partial-year decommitments. Note that the same IA procured MW can be used multiple times for partial-year decommitments as these decommitments may be for only days or weeks. For the same delivery year, self-supply or bilateral capacity transactions were used in order to decommit another 4,373 MW of full-year obligations and another 18,954 MW of partial-year obligations.

41 Again, these reported numbers represent only delivery years 2008/09 through 2010/11.

42 For example for 2010/11, DR suppliers procured 432 MW in the third IA, all of which was used to replace committed capacity for a full year. An additional 54 MW of full-year replacements were made through self-supply or bilateral transactions, and no DR suppliers submitted any partial-year capacity replacements.

43 See PJM (2011d), p. 29.

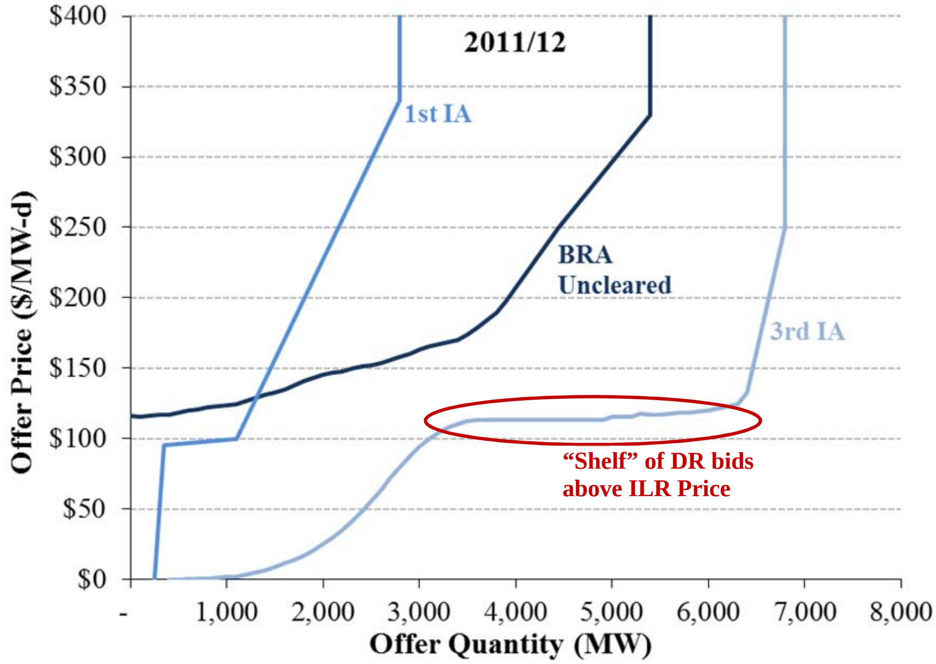
above the BRA prices otherwise awarded to ILR. As a result, prior to the 2012/13 delivery year, a rational DR supplier would either opt out of participating in any of the auctions or participate in the IAs by offering at a price above the BRA clearing price. After the elimination of ILR (and full incorporation of DR into auctions starting with the 2012/13 delivery year), this incentive was eliminated.

After the 2012/13 redesign, there have only been two incremental auctions conducted, providing limited evidence for our evaluation. However, it is noteworthy to observe from Figure 9 that the IA supply curves for the 2012/13 delivery year are very similar in shape to the uncleared portion of the BRA supply curve for prices below approximately $150/MW-day. Much of this supply is from DR offers that had similar offer levels in the BRA and IAs. It is not yet clear how the offer prices for DR supplies may differ in the third IA immediately prior to the delivery year or how substantially these offers are influenced by changing expectations about curtailment levels.

For generation supplies (both before and after the redesign), IA offer curves have been much steeper than the BRA supply curves, with most high-cost supplies dropping out prior to the IAs and many other generation suppliers offering at zero. The withdrawal of high-cost generation supplies above $150/MW-day is visible in the 2012/13 supply curves shown in Figure 8, indicating that some generators have made decisions about whether to invest in a new resource or reinvest in an existing resource contingent on the outcome of the BRA. However, we have also observed occasions when additional generation supplies that were not offered in the BRA were offered into the IAs at a zero price. For example, in the third IAs for the 2009/10 and 2010/11 delivery years, a large number of uprates were offered that were previously not offered in the BRA. Given their zero offer prices in the IAs, we believe it is likely that most of these uprate investment decisions were made based on the suppliers' longer-term outlook for capacity and energy prices and not specifically based on prices available in the IAs.

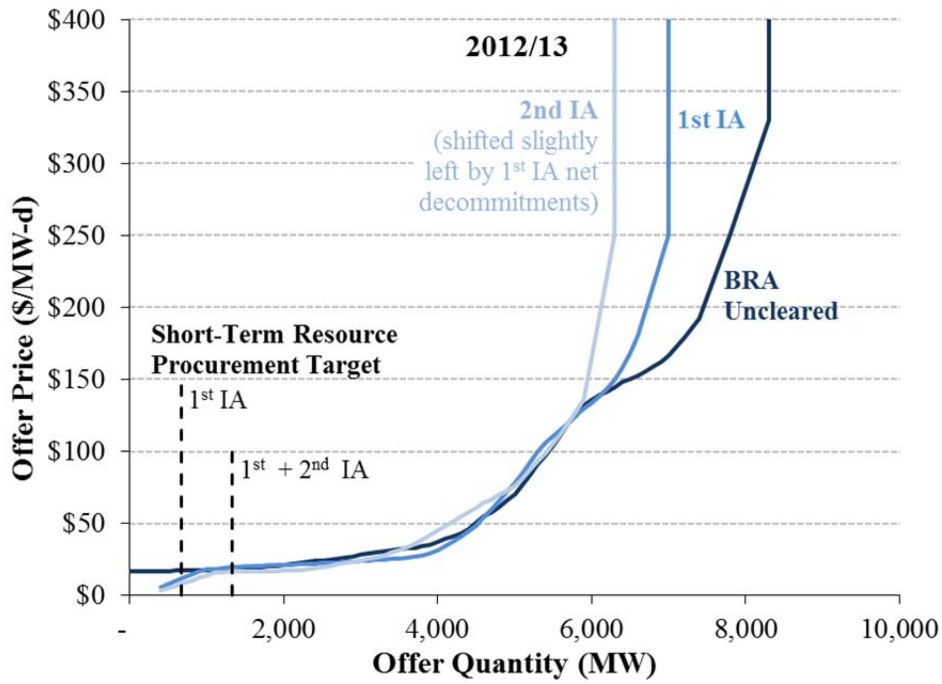
Overall, incremental auction results from the first two auctions after the redesign are promising, but more experience needs to be gained to fully assess IA performance. Prices in the IAs for the 2012/13 delivery year have been consistent with changes in market conditions between the BRA and the IAs, including load forecast reductions and the delay of the Susquehanna-Roseland transmission line. In addition to this preliminary empirical evidence, there are several other reasons to expect that IA prices under the new design will be more consistent with BRA prices and market fundamentals, including: (1) the incorporation of the incremental portion of the VRR curve in the IAs, (2) the reliability requirement adjustments that may be made prior to IAs in the future, and (3) DR and EE resources will have the option to offer into either the BRA or the IAs, which may allow some price convergence.

Figure 8
2011/12 Incremental Auction Supply Curves
(Before 2012/13 Redesign and without 2.5% Holdback)



Sources and Notes:
From PJM supplier bidding data, PJM (2011a). Smoothed to mask confidential market data.

Figure 9
2012/13 Incremental Auction Supply Curves
(After 2012/13 Redesign and with 2.5% Holdback)



Sources and Notes:
From PJM supplier bidding data, PJM (2011a). Smoothed to mask confidential market data.

C. CUMULATIVE ADDITIONS, RETIREMENTS, AND RETENTIONS

The following discussion summarizes the cumulative changes in capacity commitments from all base and incremental auctions to date—since just before the introduction of RPM through the commitments made in the most recent BRA for the 2014/15 delivery year. Unlike the previous sections covering individual auction results on a UCAP basis, the discussion *in this section refers all results on an installed capacity (ICAP) basis*.

We first summarize all gross and net additions to capacity in PJM, including resources contributing to Fixed Resource Requirement (FRR) plans and resources added through new RTO members. We report all current or planned internal generation capacity, total imports and exports, and current or planned demand-side resources. Among these total system resources, we include a breakdown of the capacity that is committed to providing resource adequacy either through FRR commitments or by clearing through auctions, as well as summarizing total resources that are RPM-qualified but that are not committed for capacity purposes either because they have gone uncleared in the auctions or because they have been excused from auctions.

We then examine in greater detail the gross and net capacity additions committed through base and incremental auctions, excluding FRR capacity and new RTO members. We explicitly report the quantities of planned capacity increases that were offered into auctions but failed to clear (indicating that they may not materialize), as well as the quantities of existing capacity that have failed to clear (indicating that they may retire). We also report the net capacity exchange between RPM auctions and FRR entities. We examine these gross and net commitments at the RTO and LDA levels, and compare committed totals to the target commitment levels required for resource adequacy. These committed net resource additions are the most relevant evidence for evaluating RPM's track record for attracting and retaining sufficient capacity for resource adequacy.

1. Net Capacity Additions (Including FRR and RTO Expansion)

Table 8 summarizes installed capacity reductions and additions in PJM relative to the pre-RPM levels in 2006/07 through results for the most recent auction for 2014/15. The table separates auction-committed capacity from FRR-committed capacity and from capacity gained through territory expansions. The top portion of the table reports total historical and planned capacity reductions and additions, while the bottom reports the total capacity commitments for resource adequacy through FRR or auctions (as well as uncommitted capacity that may retire or fail to come online).

Since RPM began with delivery year 2007/08, PJM has added 36.3 GW of ICAP through completed or planned additions, uprates to internal generation, increased imports, decreased exports, and increased demand-side resources. Of these gross additions, 4.9 GW are FRR capacity and 31.4 GW are RPM auction capacity. Derates and retirements over the same time period have totaled 8.4 GW. Of these gross reductions, 0.4 GW are FRR capacity and 8.1 GW are auction capacity. An additional 13.9 GW of pre-existing generation capacity was acquired through RTO expansions to integrate ATSI and DEOK into PJM.

Overall, these additions, reductions, and expansions have resulted in a net increase of 41.7 GW in installed capacity available to meet the required reserve margin. For the 2014/15 delivery year, of the total 205.8 GW of installed or planned capacity in PJM, 33.6 GW is committed to provide reliability through FRR commitments and another 157.3 GW is committed through RPM auctions, sufficient to exceed respective resource adequacy targets. The remaining 14.9 GW of capacity is not committed to provide resource adequacy because it was either excused from offering in auctions or failed to clear in the 2014/15 BRA.

Focusing on generation, PJM had 164.9 GW of internal generating capacity in 2006/07, immediately prior to RPM's implementation. At the outset of RPM, 23.1 GW of this existing capacity was incorporated through the FRR option. Since then, there have been gross additions of 12.7 GW of internal generation capacity in the RTO. This includes 7.6 GW of newly built or reactivated generation,(650 MW from FRR resources) and 5.1 GW of uprates to existing generation (420 MW to FRR resources).[44] These additions have been offset by 8.4 GW of reductions to internal generation through plant derates and retirements. Through the current delivery year of 2011/12, only 710 MW of generation has retired; however, based on pending deactivation requests, the rate of retirement will increase over the next three delivery years to reach a cumulative total of 5.3 GW by 2014/15. Of these retirements, 2.3 GW are coal plants, 1.7 GW are gas (primarily aging gas steam plants), 1.1 GW are oil plants, and the remainder are small units of other fuel types. Including completed and planned new units, reactivation, uprates, retirements, and derates, there has been a cumulative net addition of 4.2 GW to existing internal generating capacity in PJM through delivery year 2014/15.

PJM was a net *exporter* of 2.6 GW in 2006/07. By 2014/15, it will be a net *importer* of 6.4 GW for a total change of 9.0 GW. Gross exports declined after RPM was implemented, decreasing from 5.3 GW in 2006/07 to 1.2 GW in 2014/15. Commitments for imports increased from 2.7 GW in 2006/07 to 7.6 GW in 2014/15. Of the 9.0 GW increase in net imports, 4.2 GW occurred in 2014/15 coincident with the incorporation of DEOK into RPM, primarily from resources owned by Duke but not within the portion of Duke that was incorporated into PJM.

Demand resources have grown substantially since RPM was implemented. During the 2006/07 delivery year, 1.7 GW of demand-side resources contributed to resource adequacy as Active Load Management ("ALM"). For 2014/15, 16.4 GW of DR and EE capacity has been committed through FRR or offered into RPM auctions (in ICAP terms).[45]

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44 650 MW of new generation that offered into the 2014/15 auction did not clear and may not come online.

45 Note that the apparent decrease in demand resources for 2013/14 relative to the prior and subsequent years is somewhat misleading. The reason for this apparent drop is that no incremental auctions have yet been conducted for 2013/14. We expect that subsequently planned resources that have offered into the 2012/13 IAs and 2014/15 BRA will also offer into the 2013/14 IAs when they are conducted.

Table 8
Cumulative Changes in Capacity under RPM
(ICAP MW)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
INTERNAL GENERATION	**164,914**	**164,556**	**165,327**	**165,966**	**167,553**	**171,655**	**171,559**	**181,243**	**183,009**
Existing Generation Prior to RPM	**164,914**	**164,914**	**164,914**	**164,914**	**164,914**	**165,663**	**166,460**	**177,035**	**178,769**
Non-FRR Capacity as of 2006/07	141,831	141,831	141,831	141,831	141,831	141,831	141,831	141,831	141,831
FRR Capacity as of 2006/07	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083
ATSI/DEOK Prior to Joining PJM	n/a	n/a	n/a	n/a	n/a	749	1,546	12,121	13,855
Generation Reductions	n/a	**(904)**	**(1,269)**	**(2,110)**	**(2,412)**	**(2,675)**	**(5,713)**	**(7,136)**	**(8,446)**
Retirements	n/a	*(340)*	*(440)*	*(440)*	*(617)*	*(710)*	*(3,035)*	*(4,331)*	*(5,341)*
FRR Capacity	n/a	-	-	-	-	-	-	-	-
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	(322)
Auction Capacity (w/o ATSI/DEOK)	n/a	(340)	(440)	(440)	(617)	(710)	(3,035)	(4,331)	(5,019)
Derates	n/a	*(564)*	*(829)*	*(1,670)*	*(1,795)*	*(1,965)*	*(2,678)*	*(2,805)*	*(3,105)*
FRR Capacity	n/a	(94)	(138)	(357)	(357)	(357)	(361)	(361)	(364)
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	(470)	(691)	(1,313)	(1,439)	(1,608)	(2,318)	(2,445)	(2,742)
Generation Additions	n/a	**546**	**1,681**	**3,155**	**5,043**	**8,243**	**10,387**	**11,104**	**12,686**
New Generation	n/a	*129*	*340*	*882*	*1,845*	*3,838*	*4,924*	*5,662*	*6,763*
FRR Capacity	n/a	-	-	-	595	595	595	655	655
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	685	708
Auction Capacity (w/o ATSI/DEOK)	n/a	129	340	882	1,250	3,243	4,329	4,322	5,400
Uprates	n/a	*417*	*1,040*	*1,947*	*2,896*	*3,573*	*4,622*	*4,610*	*5,083*
FRR Capacity	n/a	64	84	254	254	295	354	380	416
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	352	956	1,693	2,641	3,279	4,268	4,230	4,667
Reactivations	n/a	-	*302*	*326*	*303*	*832*	*841*	*832*	*841*
FRR Capacity	n/a	-	-	-	-	-	-	-	-
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	-	302	326	303	832	841	832	841
New Generation Later Cancelled	n/a	**-**	**-**	**8**	**8**	**424**	**426**	**240**	**-**
NET IMPORTS	**(2,563)**	**(1,390)**	**(1,590)**	**474**	**35**	**(305)**	**1,375**	**2,173**	**6,390**
Gross Imports	*2,711*	*2,984*	*2,616*	*2,715*	*3,413*	*3,084*	*4,159*	*4,797*	*7,620*
Imports to FRR	n/a	1,275	858	850	1,131	1,095	1,506	1,265	3,328
Imports to Auctions	n/a	1,709	1,758	1,865	2,282	1,989	2,653	3,532	4,292
Gross Exports	*(5,274)*	*(4,374)*	*(4,206)*	*(2,241)*	*(3,378)*	*(3,389)*	*(2,784)*	*(2,625)*	*(1,230)*
DEMAND RESOURCES	**1,679**	**2,135**	**4,467**	**7,576**	**9,344**	**11,026**	**14,621**	**13,732**	**16,350**
FRR DR/EE	n/a	432	438	438	452	450	473	473	501
Auction DR/EE (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	30	124	1,342	1,082
ILR and Auctions (w/o ATSI/DEOK)	1,679	1,703	4,029	7,138	8,892	10,546	14,024	11,917	14,767
TOTAL INSTALLED CAPACITY	**164,030**	**165,300**	**168,203**	**174,015**	**176,930**	**182,378**	**187,556**	**197,150**	**205,762**
Committed Capacity	**n/a**	**163,279**	**165,392**	**172,135**	**174,487**	**174,987**	**171,643**	**187,280**	**190,894**
FRR Commitments	n/a	24,717	24,954	25,316	26,306	25,921	26,302	25,793	33,613
ILR and Cleared DR/EE	n/a	1,703	4,029	7,138	8,892	10,576	8,065	9,634	14,458
Cleared Gen (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	3	-	10,908	8,501
Cleared PJM Gen (w/o ATSI/DEOK)	n/a	135,150	134,693	137,858	137,015	136,548	134,686	137,413	130,030
Cleared Imports	n/a	1,709	1,716	1,823	2,274	1,939	2,590	3,532	4,292
Uncommitted Capacity	**n/a**	**2,020**	**2,812**	**1,880**	**2,444**	**7,391**	**15,913**	**9,870**	**14,868**
FRR Excused	n/a	43	357	553	759	1,178	1,692	1,194	2,546
Uncleared DR/EE	n/a	n/a	n/a	n/a	n/a	n/a	6,083	3,625	1,391
Uncleared Gen (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	746	1,546	1,898	4,031
Uncleared PJM Gen (w/o ATSI/DEOK	n/a	1,510	2,047	1,013	1,145	5,015	6,489	3,143	6,191
Uncleared Imports	n/a	0	43	42	8	50	64	-	-
Other Excused	n/a	467	365	272	531	402	40	10	710

Sources and Notes: Generation, DR, and EE are cumulative for all BRAs and IAs, reported in ICAP terms, PJM (2011a).

Among all of these existing and planned resources, 191.1 GW of installed capacity is committed for 2014/15, including 33.6 GW of FRR resources, 33.6 GW of cleared demand resources, 138.5 GW of cleared internal generation, and 4.3 GW of cleared imports. Another 4.0 GW of incremental commitments are expected to be procured, associated with the short-term resource procurement target.[46] Uncommitted existing or planned capacity resources total 14.8 GW. These uncommitted resources include 2.5 GW of excused FRR capacity, 0.7 GW of other excused generation, 1.4 GW of uncleared demand resources, and 10.2 GW of uncleared internal generation. Some of these uncleared resources represent planned resources that may not come online because they have failed to clear the BRA, while others represent existing resources that may retire before the 2014/15 delivery year.

It is particularly instructive to examine the changes in resource commitments between the 2013/14 and 2014/15 years, when the proposed EPA HAP regulations are expected to come into force. Auction-based internal generation commitments decreased by 9.8 GW between the two base auctions, caused primarily by a response to the environmental regulations as well as a reduction in load forecasts. Uncleared internal generation resources totaled 10.2 GW (up from 5.0 GW in 2013/14), mostly consisting of coal units in the unconstrained RTO. There were also 2.5 GW of FRR-excused resources (up from 1.2 GW) and 0.7 GW of other excused resources (increased from near zero). These withdrawals may also be related to a response to the HAP regulation. Despite these reductions in internal generation commitments, the RTO has sufficient existing and planned resources procured to meet resource adequacy requirements in 2014/15 (assuming the 2.5% STRPR will be successfully procured in the IAs). The internal reductions in generation commitment were compensated for by a large 4.8 GW increase in demand resource commitments, a 1.4 GW reduction in exports, and other resource adjustments (all in ICAP).[47]

2. Net Capacity Additions (Excluding FRR and RTO Expansion)

Excluding FRR and new RTO members, PJM has added 28.4 GW (ICAP) of gross committed and 13.1 GW of net committed capacity supply under RPM auctions, as shown in Figure 10 and Table 9. The gross committed additions are from 11.8 GW of new demand resources, 6.9 GW of increases in net imports, 4.8 GW of new generation, 4.1 GW of uprates, and 0.8 GW of reactivations. These additions were offset by 15.3 GW of gross capacity reductions, including 5.0 GW of retirements, 2.7 GW of derates, 6.8 GW of capacity removed from auctions for FRR, and 0.7 GW of generation excused from auctions. As discussed in Section II.A, these net increases have been sufficient to sustain capacity surpluses in the RTO at prices below Net CONE despite some load growth over the period and environmental challenges to supply.

Figure 10 shows these gross and net capacity additions relative to the pre-RPM installed capacity. The red horizontal line at 140 GW shows the 2006/07 installed capacity, including all internal generation, net imports, and Active Load Management resources. The left panel of the chart shows gross capacity reductions of 15.3 GW and the composition of these decommitments. The right panel shows the composition of 28.4 GW in increased resource commitments. A total capacity of 153 GW for the 2014/15 delivery year, after reductions to existing capacity and

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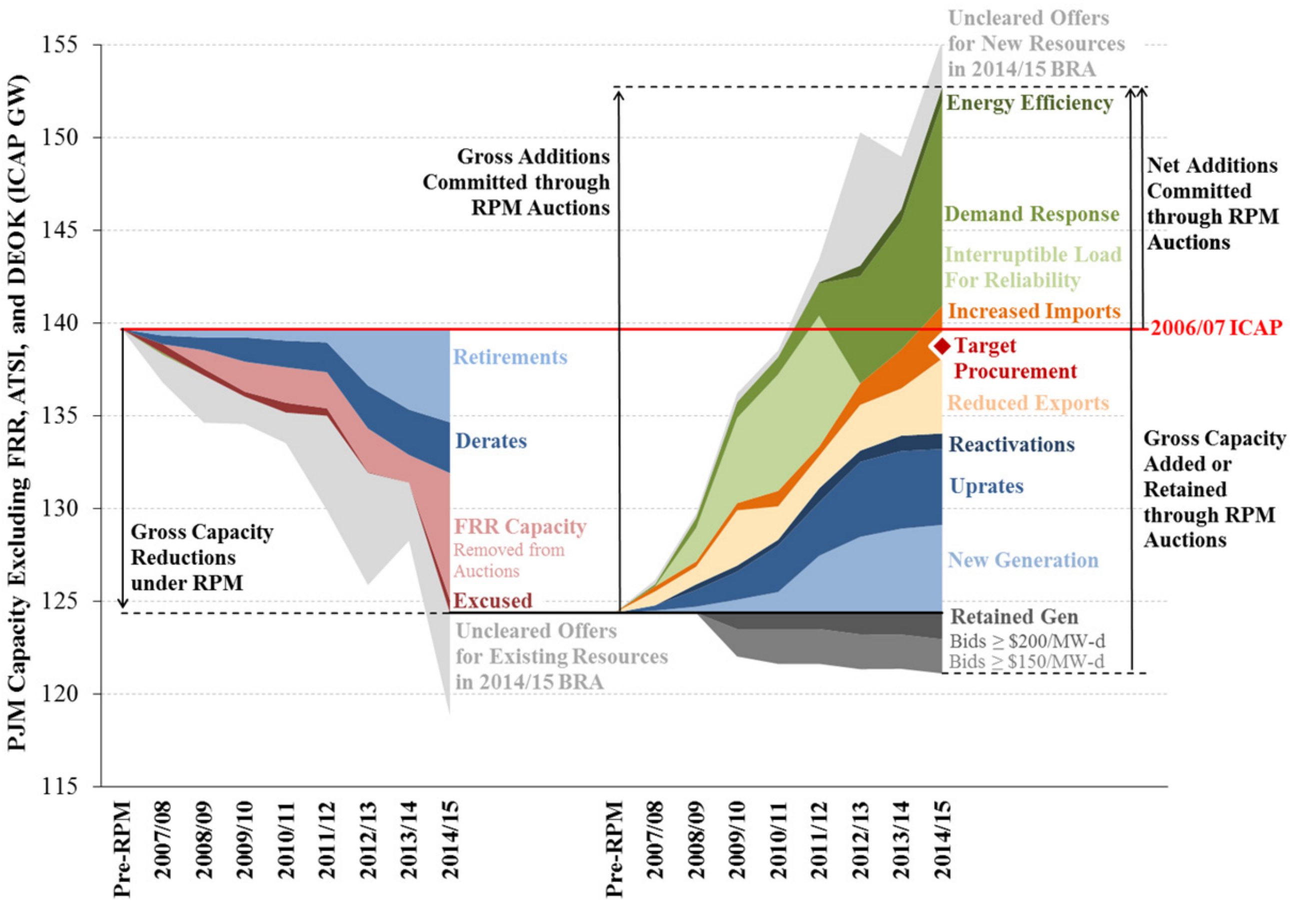
[46] The STRPT is reported here on an ICAP basis for the entire RTO including territory expansions, see PJM (2011b).

[47] Increases in imports and FRR commitments are not reported here as offsetting factors because these commitment increases were largely related to the DEOK territory expansion.

committed increases, is indicated by the dashed line at the top of the right side of the figure. This 2014/15 capacity is greater than the target procurement to meet resource adequacy requirements for the 2014/15 delivery year (shown as the red diamond), demonstrating a capacity surplus through 2014/15.

Figure 10
RTO Net Capacity Additions Committed in RPM Auctions
Excluding FRR Capacity and RTO Expansions



Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms.
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
From PJM bid and resource data, PJM (2007a).

Reductions. The 15.3 GW (ICAP) of gross reductions include retirements, derates, reductions in imported capacity, withdrawal of FRR capacity that previously offered into auctions, and excused capacity that previously offered into auctions. Deducting these from the 2006/07 baseline creates the new baseline of remaining existing supply at 124 GW.

- The largest share of reductions has been from FRR resources that were offered into the first RPM auctions in 2007/08 but have since stopped offering into RPM auctions. Many of these of 6.8 GW of FRR withdrawals occurred between the 2013/14 and 2014/15 auctions and are likely related to the proposed EPA regulations.

- Retirements of 5.0 GW and derates of 2.7 GW comprise most of the remaining reductions, with a small contribution from other capacity excused from the RPM auctions.
- As shown, there are also 5.0 GW of uncleared existing generation resources that offered into the 2014/15 BRA and failed to clear, but have not yet retired. These resources are shown in light gray at the bottom of the right panel. We do not deduct these from the existing baseline because they have not yet retired and could yet commit through future incremental or base auctions. However, we note that these units would likely retire in the future if they also fail to clear in subsequent auctions. As explained in Section II.A, these potential retirements could reduce, but not eliminate, the overall capacity surplus in the RTO.

Additions: Gross additions under RPM include newly-built generation, uprates to existing generation, reactivations, reduced exports, increased imports, and increases to demand-side resources. Adding these to the 124 GW baseline of remaining existing resources yields a installed capacity of 153 GW for the 2014/15 delivery year. These increases consider only committed additions, while uncleared new resources are shown in light gray at the top of the right panel. The 28.4 GW (ICAP) of committed resource additions under RPM are composed of:

- 11.8 GW of increased demand response and energy efficiency (relative to the pre-RPM levels of ALM resources). Levels of DR under RPM have been steadily increasing, with the exception of 2012/13, when many suppliers stopped using the ILR mechanism and were incorporated into RPM auctions. However, additional demand resources may yet be procured in through the final incremental auction for the 2012/13 delivery year.
- 4.9 GW of new generation construction, 4.1 GW of capacity uprates, and 0.8 GW of reactivations.
- 6.9 GW of increased imports, resulting in PJM becoming a net importer of capacity.
- 2.5 GW of offers for new resources that failed to clear for the in 2014/15 delivery year due to offer prices in excess of auction clearing prices. Prior auctions showed similar or much larger amounts of uncleared new resources. We do not treat these uncleared new resources as additions, however, even though they could have been committed at higher market prices, if they had been needed.

Retentions: "Retained capacity" under RPM is a somewhat arbitrary determination, but for reference we show the quantity of capacity that has cleared in RPM auctions after offering their capacity at prices above \$150/MW-day and \$200/MW-day thresholds. These relatively high-priced offers from existing resources indicate that the resource required significant investments and would likely have retired had they failed to clear in the auctions.[48] Based on those indicators, 3.3 GW of generation capacity has been retained through RPM after having offered into the RPM auctions at prices of \$150/MW-day or more. All of these resources were in the

[48] We recognize that the identification of "retained" generation under RPM is somewhat arbitrary and dependents on what alternative resource adequacy construct would exist in place of RPM. We do not attempt any such theoretical comparison but instead simply report resources that may have been considering retirement (as indicated by their auction bid levels) but cleared in RPM auctions and thus remained committed.

MAAC LDA, where prices cleared above the $150/MW-day threshold. Clearing prices in the unconstrained RTO have been generally been lower than this threshold, but may also have retained generation that otherwise would have retired.[49]

Table 9
RTO Net Capacity Additions Committed in RPM Auctions
Excluding FRR Capacity and RTO Expansions

	Pre-RPM	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EXISTING CAPACITY IN 2006/07									
Internal Generation	164,914	164,914	164,914	164,914	164,914	164,914	164,914	164,914	164,914
Active Load Management	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679
Imports	1,436	1,436	1,436	1,436	1,436	1,436	1,436	1,436	1,436
Exports	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)
2006/07 FRR Generation	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)
Total Capacity in 2006/07	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**
CAPACITY REDUCTIONS									
Retirements		(340)	(440)	(440)	(617)	(710)	(3,035)	(4,331)	(5,019)
Derates		(470)	(691)	(1,313)	(1,439)	(1,608)	(2,318)	(2,445)	(2,742)
Net FRR Capacity Removed from Auctions		(0)	(998)	(1,614)	(1,908)	(1,943)	(2,345)	(1,492)	(6,830)
Excused Capacity		(467)	(365)	(272)	(531)	(402)	(40)	(10)	(710)
Net Reductions in ILR		(99)	-	-	-	-	-	-	-
Total Reductions		**(1,376)**	**(2,495)**	**(3,639)**	**(4,494)**	**(4,663)**	**(7,737)**	**(8,277)**	**(15,300)**
Uncleared Offers for Existing Resources		*(1,291)*	*(1,866)*	*(595)*	*(796)*	*(3,820)*	*(5,360)*	*(2,976)*	*(4,958)*
RETAINED CAPACITY									
Bids Above $200/MW-d		0	0	870	871	871	1,156	1,169	1,417
Additional Bids Above $150/MW-d		-	-	1,478	1,874	1,874	1,874	1,845	1,845
Total Prevented Reductions		**0**	**0**	**2,348**	**2,745**	**2,746**	**3,031**	**3,015**	**3,262**
CAPACITY INCREASES									
New Generation		129	340	707	1,118	3,079	4,095	4,307	4,750
New Generation Later Cancelled		-	-	8	8	8	8	240	-
Uprates		279	902	1,513	2,522	2,885	4,044	4,182	4,088
Reactivations		-	302	326	303	752	606	832	841
Net Reductions in Exports		754	953	2,983	1,799	1,749	2,472	2,546	4,040
Net Increases in Imports		273	280	387	838	503	1,154	2,096	2,856
ILR & DR Additions (from ALM baseline)		124	2,351	5,458	7,214	8,793	5,787	6,917	11,006
Energy Efficiency		-	-	-	-	74	567	654	793
Total Cleared Increases		**1,559**	**5,128**	**11,381**	**13,801**	**17,842**	**18,732**	**21,773**	**28,375**
Uncleared Offers for New Resources		*219*	*224*	*460*	*357*	*1,245*	*7,183*	*2,834*	*2,521*
Net Committed Capacity Additions	**0**	**183**	**2,633**	**7,742**	**9,307**	**13,178**	**10,995**	**13,497**	**13,075**
Installed Capacity Plus Net Additions	**139,672**	**139,855**	**142,305**	**147,414**	**148,979**	**152,850**	**150,668**	**153,169**	**152,747**

Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported).
From PJM bid and resource data, PJM (2007a).

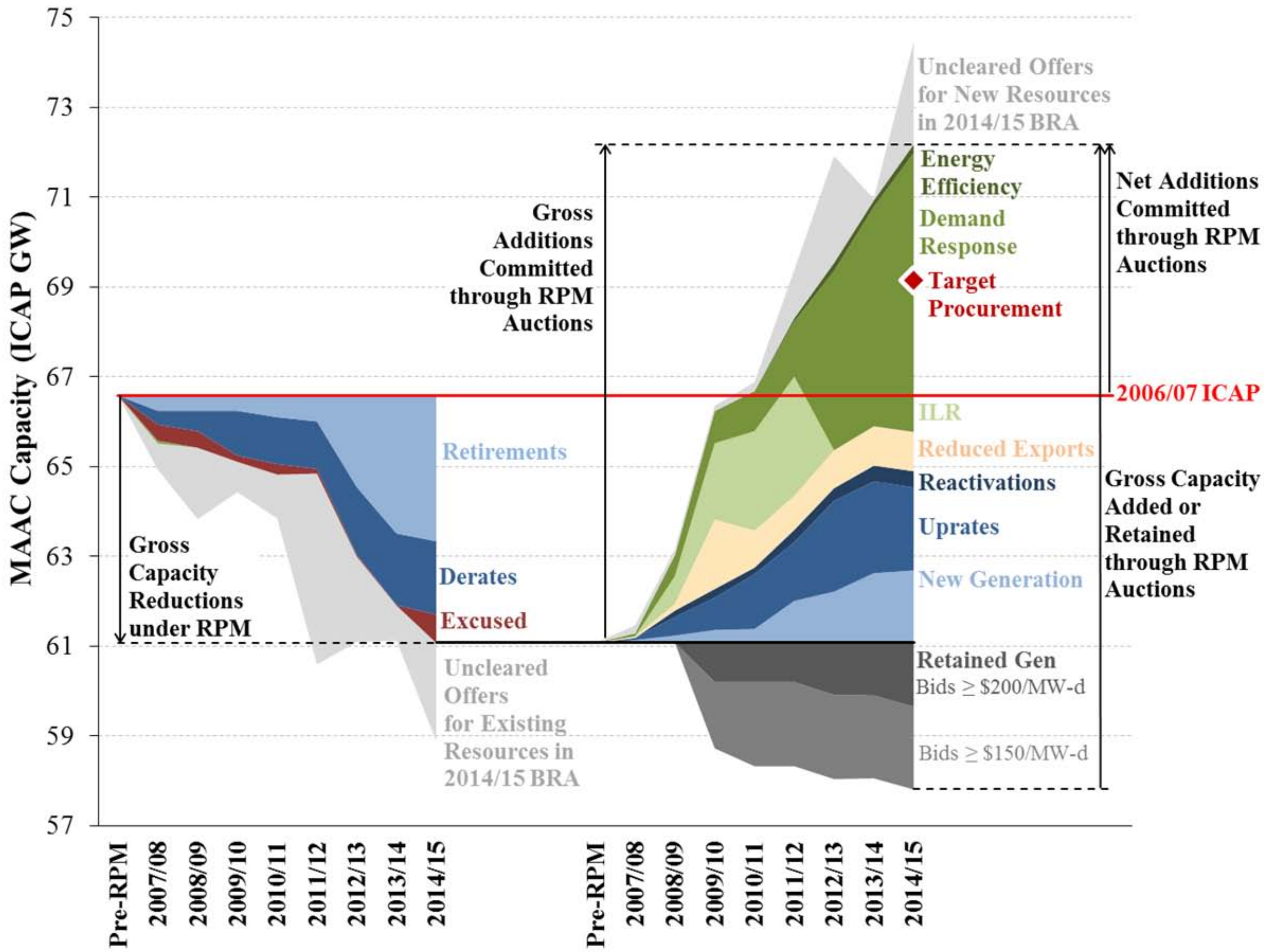
3. Net Additions Committed in the MAAC LDA

Figure 11 and Table 10 report the capacity reductions and committed additions through RPM auctions for the Mid-Atlantic Area Council (MAAC) LDA. In MAAC, a net 5.6 GW (ICAP) of capacity increases has been committed through 2014/15. Compared to the RTO, the LDA saw

[49] Prices cleared above $150/MW-day only one time in the unconstrained RTO, clearing at $174/MW-day in 2010/11. See Table 1.

proportionately somewhat greater reductions in generating capacity, fewer generation additions, but greater increases in demand resources.[50] As of the recent BRA for the 2014/15 delivery year, MAAC has slightly lower uncleared offers for existing resources and slightly more uncleared offers for new resources, consistent with a smaller overall capacity surplus in the LDA.[51]

Figure 11
MAAC Net Capacity Additions Committed in RPM Auctions



Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms.
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
From PJM bid and resource data, PJM (2007a).

Reductions. Among the 5.5 GW of capacity reductions, the largest share is accounted for in the 3.2 GW of pending retirements, scheduled to occur starting in 2012/13. Capacity derates of

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50 As a fraction of 2014/15 installed capacity and committed increases, generation additions account for 6.3% of the RTO total and 5.3% of the MAAC total, while demand resource increases account for 7.8% in the RTO and 8.9% in MAAC; generation reductions represented 5.1% of the 2014/15 capacity in the RTO and 6.8% in MAAC.

51 As a fraction of 2014/15 installed capacity and committed increases, uncleared existing resources were 3.2% in the RTO and 2.4% in MAAC while uncleared new resources were 1.7% in the RTO and 3.2% in MAAC.

1.6 GW comprise most of the remaining reductions, with the remaining 0.6 GW from an increase in excused capacity. An additional 1.7 GW of uncleared existing generation resources are units that may be at risk for retirement if they do not clear in upcoming incremental or base auctions.

Additions. The 11.1 GW of additional capacity commitments in MAAC are composed of 6.4 GW of increases in demand-side resources, 1.6 GW of new generation, 1.8 GW of uprates, and 0.9 GW of reductions in exports. In addition to the capacity additions that have been committed under RPM auctions, another 2.3 GW of uncleared new supply was available in the most recent auction.

Retentions. 3.3 GW of generation capacity has been retained through RPM after having offered into the RPM auctions at prices of $150/MW-day or more. The largest quantity of capacity retention occurred in the BRA for the 2009/10 delivery year, in which several generation resources, especially in SWMAAC, required environmental upgrades to continue operating, as discussed in our 2008 report.[52]

Table 10
MAAC Net Capacity Additions Committed in RPM Auctions
(ICAP MW)

	Pre-RPM	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EXISTING CAPACITY IN 2006/07									
Internal Generation	67,336	67,336	67,336	67,336	67,336	67,336	67,336	67,336	67,336
Active Load Management	795	795	795	795	795	795	795	795	795
Exports	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)
2006/07 FRR Generation	-	-	-	-	-	-	-	-	-
Total Capacity in 2006/07	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**
CAPACITY REDUCTIONS									
Retirements		(340)	(340)	(340)	(482)	(575)	(2,036)	(3,070)	(3,243)
Derates		(307)	(454)	(997)	(1,044)	(1,059)	(1,504)	(1,595)	(1,634)
Excused Capacity		(357)	(365)	(137)	(232)	(102)	(40)	(10)	(630)
Net Reductions in ILR		(64)	-	-	-	-	-	-	-
Total Reductions		**(1,067)**	**(1,159)**	**(1,474)**	**(1,758)**	**(1,736)**	**(3,580)**	**(4,675)**	**(5,507)**
Uncleared Offers for Existing Resources		*(400)*	*(1,141)*	*(32)*	*(566)*	*(3,181)*	*(1,563)*	*(761)*	*(1,698)*
RETAINED CAPACITY									
Bids Above $200/MW-d		0	0	870	871	871	1,156	1,169	1,417
Additional Bids Above $150/MW-d		-	-	1,478	1,874	1,874	1,874	1,845	1,845
Total Prevented Reductions		**0**	**0**	**2,348**	**2,745**	**2,746**	**3,031**	**3,015**	**3,262**
CAPACITY INCREASES									
New Generation		66	164	281	303	929	1,134	1,314	1,614
New Generation Later Cancelled		-	-	8	8	8	8	240	-
Uprates		46	414	721	1,222	1,309	2,022	2,044	1,849
Reactivations		-	142	192	143	272	281	352	361
Net Reductions in Exports		37	149	1,548	825	760	847	875	875
ILR & DR Additions (from ALM baseline)		64	1,092	2,416	3,104	3,880	3,988	4,884	6,209
Energy Efficiency		-	-	-	-	74	182	147	193
Total Cleared Increases		**212**	**1,961**	**5,165**	**5,605**	**7,232**	**8,461**	**9,855**	**11,100**
Uncleared Offers for New Resources		*182*	*128*	*117*	*201*	*1,075*	*2,379*	*34*	*2,283*
Net Committed Capacity Additions	**0**	**(855)**	**801**	**3,692**	**3,848**	**5,496**	**4,881**	**5,181**	**5,593**
Installed Capacity Plus Net Additions	**66,581**	**65,727**	**67,383**	**70,273**	**70,429**	**72,077**	**71,463**	**71,762**	**72,175**

Sources and Notes:

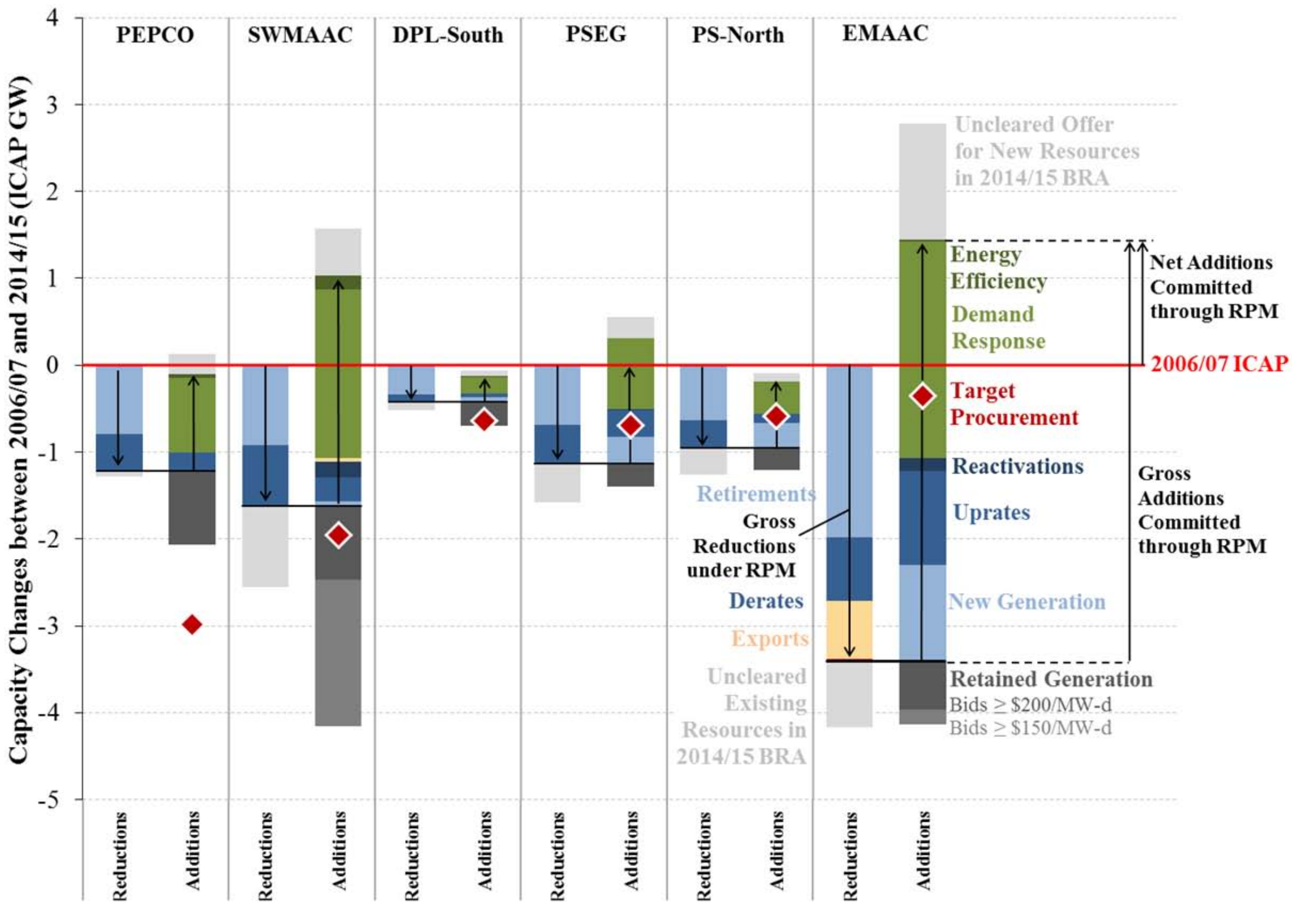
52 See Pfeifenberger and Newell, *et al.* (2008), pp. 15, 22-24, 112-115.

All generation, DR, and EE values are cumulative totals in ICAP terms. Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported). From PJM bid and resource data, PJM (2007a).

4. Net Additions Committed in Smaller LDAs

Figure 12 and Table 11 summarize capacity reductions and additions similar to that presented in the above discussion for the RTO and MAAC. This information is presented for all of the other, smaller LDAs currently modeled in RPM. For these LDAs, these reductions and additions are not shown on an annual basis but, rather, as the total changes between pre-RPM levels and the results for the 2014/15 delivery year.

Figure 12
LDA Net Capacity Additions Committed in RPM Auctions



Sources and Notes:

All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
Target procurement is reliability requirement less STRPT and CETL, converted to ICAP equivalent, from PJM (2011b). From PJM bid and resource data, PJM (2007a).

Our primary observations are as follows:

- The largest of these LDAs—EMAAC, SWMAAC, and PSEG—had 1,440 MW, 1,030 MW, and 310 MW of *net capacity additions* under RPM, while the smallest

LDAs—PSEG-North, DPL-South, and PEPCO—had 190 MW, 130 MW and 100 MW of *net reductions* in LDA-internal committed capacity.

- Even though the smallest LDAs had net reductions in committed LDA-internal capacity, the total 2014/15 capacity commitments are sufficient to ensure resource adequacy and, in fact, represent an overall surplus relative to the 2014/15 BRA target procurement (shown as a red diamond in the figure, such that capacity above the red dot represents surplus). Target procurement for LDA-internal resources has decreased primarily due to increased import capabilities (CETL).
- Most LDA-internal capacity increases were from demand response, although EMAAC, PSEG-North, and PSEG also had large increases from new generation and uprates.
- Every LDA has had capacity reductions from retirements and capacity derates, and these have been proportionally larger in the smallest LDAs. These capacity reductions were part of the reason that these LDAs have been modeled as constraint under RPM; the reductions also contributed to triggering transmission upgrades that have increased import capabilities into these locations.
- PEPCO, SWMAAC, and EMAAC all retained large amounts of existing generation with high bids above $150/MW-day, primarily related to the cost of retrofits required to meet state and federal environmental regulations implemented or proposed since 2006/07.
- Most LDAs other than DPL-South and PEPCO also show that a sizeable fraction of their existing generation did not clear in the base auction for 2014/15. These uncleared existing resources were not needed for reliability in the most recent auction, partly because of reductions in the load forecast and increases in transmission import limits. Unless they are cleared in future incremental auctions, these resources must be expected to retire.

All LDAs also had uncleared offers for new resources in 2014/15, ranging from 2.3% to 4.3% of installed resources. In LDAs other than EMAAC, 43% to 70% of these uncleared new resources were demand-side resources, with the remaining 30% to 57% from uncleared uprates to existing generation. EMAAC was the only LDA with uncleared new generation in 2014/15 (650 MW). The lack of uncleared offers for new generation in the other LDAs presumably is related to the lack of need and developer cautiousness surrounding the recession and proposed transmission upgrades. It is important to note, however, that there were other uncleared offers for new generation in prior auctions, but these previously-offered new generating plants were not offered for 2014/15. In prior auctions, *all LDAs* had additional uncleared offers for new resources which could have been procured at higher prices had they been needed for reliability.

Table 11
LDA Net Capacity Additions Committed in RPM Auctions

	RTO	MAAC	EMAAC	PSEG	PS-North	DPL-South	SWMAAC	PEPCO
EXISTING CAPACITY IN 2006/07								
Internal Generation	164,914	67,336	33,022	8,129	4,475	1,715	11,639	6,344
Active Load Management	1,679	795	287	121	60	17	227	-
Imports	1,436	-	-	-	-	-	-	-
Exports	(5,274)	(1,549)	(4)	-	-	-	(48)	-
2006/07 FRR Generation	(23,083)	-	-	-	-	-	-	-
Total Capacity in 2006/07	**139,672**	**66,581**	**33,305**	**8,249**	**4,535**	**1,732**	**11,818**	**6,344**
CAPACITY REDUCTIONS								
Retirements	(5,019)	(3,243)	(1,983)	(686)	(629)	(342)	(922)	(790)
Derates	(2,742)	(1,634)	(727)	(448)	(325)	(75)	(697)	(424)
Net Increases in Exports	-	-	(670)	-	-	-	-	-
Net FRR Capacity Removed from Auctions	(6,830)	-	-	-	-	-	-	-
Excused Capacity	(710)	(630)	(24)	(1)	-	-	-	-
Total Reductions	**(15,300)**	**(5,507)**	**(3,404)**	**(1,135)**	**(954)**	**(417)**	**(1,619)**	**(1,214)**
Uncleared Offers for Existing Resources	*(4,958)*	*(1,698)*	*(766)*	*(439)*	*(301)*	*(101)*	*(932)*	*(67)*
RETAINED CAPACITY								
Bids Above $200/MW-d	1,417	1,417	563	257	257	275	853	853
Additional Bids Above $150/MW-d	1,845	1,845	166	-	-	-	1,679	-
Total Prevented Reductions	**3,262**	**3,262**	**729**	**257**	**257**	**275**	**2,532**	**853**
CAPACITY INCREASES								
New Generation	4,750	1,614	1,108	309	291	52	57	2
Uprates	4,088	1,849	1,079	304	101	34	269	206
Reactivations	841	361	151	16	3	-	181	-
Net Reductions in Exports	4,040	875	-	-	-	-	48	-
Net Increases in Imports	2,856	-	-	-	-	-	-	-
ILR & DR Additions (from ALM baseline)	11,006	6,209	2,487	813	369	197	1,935	864
Energy Efficiency	793	193	20	5	-	5	156	42
Total Cleared Increases	**28,375**	**11,100**	**4,845**	**1,446**	**763**	**288**	**2,646**	**1,114**
Uncleared Offers for New Resources	*2,521*	*2,283*	*1,338*	*248*	*101*	*68*	*545*	*234*
Net Committed Capacity Additions	**13,075**	**5,593**	**1,442**	**311**	**(190)**	**(129)**	**1,027**	**(100)**
Installed Capacity Plus Net Additions	**152,747**	**72,175**	**34,747**	**8,560**	**4,345**	**1,603**	**12,845**	**6,244**

Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported).
From PJM bid and resource data, PJM (2007a).

D. GENERATION INTERCONNECTION QUEUE

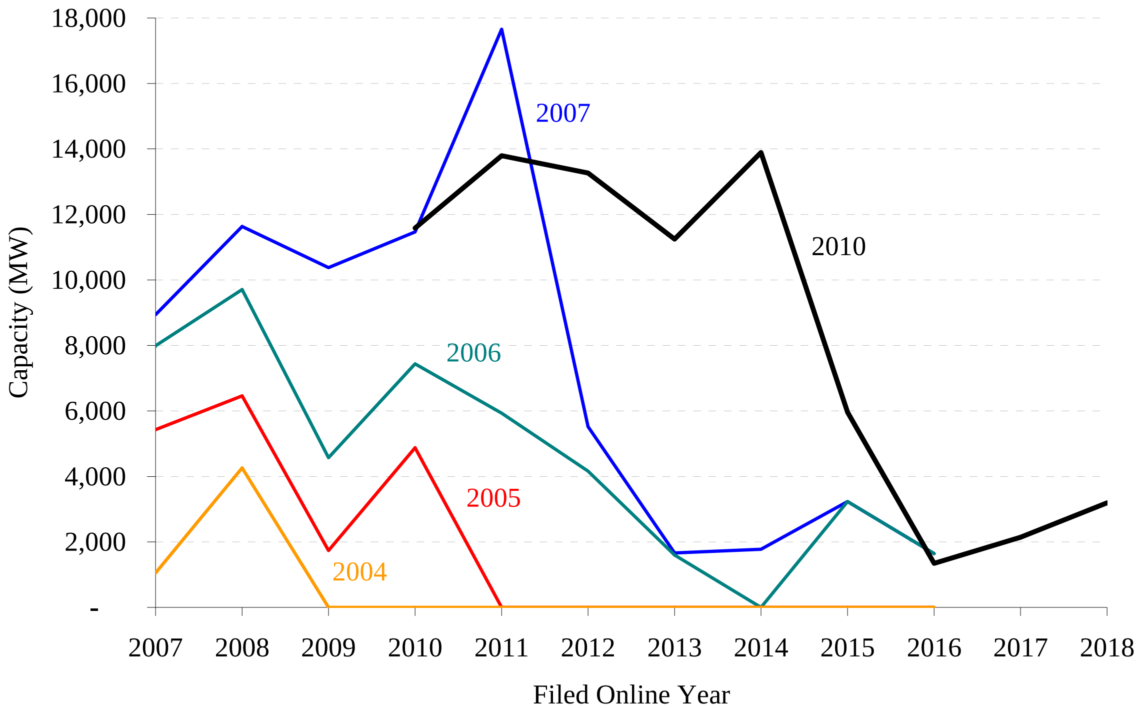
In our 2008 RPM evaluation, we reported that RPM had stimulated the development of an unprecedented amount of potential new resources, including approximately 33,000 MW of new generation projects in PJM's interconnection queue that were eligible to offer into future RPM auctions, with capacity that was not already committed as the result of the first five base auctions. Approximately 28,000 MW of this capacity was from non-renewable resources for which RPM-based capacity payment are likely a major driver.[53] We also documented that a significant expansion in interconnection requests had occurred by 2007, and we observed a spike

[53] 2008 RPM Report, pages 38-39

in interconnection requests with an online date of 2011, just in time for the first 3-year forward auction for the 2011/12 delivery year.

Figure 13 below shows interconnection requests for the period from 2004 through 2007, updated with queue data from 2010, as summarized by the IMM. The total capacity of generation projects submitted in the queue as of 2010 remains high despite the economic downturn, reductions in load forecasts and associated reliability requirements, and significant expansion of capacity from demand-response resources. In addition, the pattern we previously observed has been maintained despite the fundamental economic changes since 2007: at the end of 2010, just prior to the BRA auction for the 2014/15 delivery year, the interconnection queue shows a similar spike of interconnection requests with an online date of 2014.

Figure 13
Capacity of Active Generation Projects in Interconnection Queue
(2004-2007 and 2010, by online date)



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

Table 12 shows total unforced capacity (*i.e.*, derated to the resources' capacity value) of active interconnection requests currently in the PJM queue by LDA. As shown, generation projects in the interconnection queue that have already passed the feasibility study and, thus, qualify to be bid into RPM, have remained high compared to needs at both the RTO and LDA levels. Interconnection requests with over 26,000 MW qualify for RPM participation the RTO-wide level, 13,000 MW of interconnection requests qualify in MAAC, 3,100 MW in SWMAAC, 1,400 MW in PEPCO, 7,300 MW in EMAAC, 1,900 MW in PSEG, and 500 MW in DPL. We recognize that the status of the projects behind these interconnection requests is generally uncertain, and the same generation project may be represented in multiple interconnection requests.[54] However, the number of interconnection requests, their aggregate capacity value, and their locational distribution suggest that sufficient new generating resources stand ready to be developed if market conditions warrant such additions and development challenges can be overcome.

Table 12
Planned Projects Eligible for RPM Participation

Locational Deliverability Area	TOTAL RPM QUALIFIED MW	TOTAL UNDER STUDY MW
DPL	500.2	1,751.8
PSEG	1,932.1	4,274.0
EMAAC	7,318.7	12,730.6
PEPCO	1,453.8	2,283.8
SWMAAC	3,093.8	3,923.8
MAAC	12,980.8	22,570.2
Unconstrained RTO	13,564.7	21,665.3
RTO TOTAL	**26,545.5**	**44,235.5**

Sources and Notes:
[1] PJM queue data downloaded on 8/15/2011.
[2] Quantities are calculated based on net summer capacity (wind and solar derated to capacity value).

Our 2008 RPM report identified delays in the interconnection process as a significant concern.[55] At that time, PJM had accumulated a substantial backlog of overdue interconnection studies in its interconnection process, following a surge of interconnection requests in response to the implementation of RPM and state renewable portfolio standards.

To improve the interconnection study process, PJM reconvened the Regional Planning Process Working Group and implemented a number of changes to streamline the interconnection process.[56] The most significant accomplishments are:

- PJM introduced three-month queue cycles. As a result, System Impact and Feasibility Studies are now conducted in four cycles per year (as opposed to two cycles per year previously).

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54 For example, the 3,100 MW of RPM-qualifying interconnection requests in SWMAAC include a new 1,640 MW nuclear plant in the BG&E service area which, even if developed successfully, would not become available in time for the next several BRAs. Similarly, the PEPCO queue includes interconnection requests for two 725 MW combined cycle plants in the same county, which likely represent overlapping interconnection requests from the same projects. However, even a single 725 MW CC plant built in PEPCO would satisfy load growth-related resource adequacy needs for many years.

55 Section V.B.

56 Interconnection Process Changes and Timetable, presented at RPPWG in March 2009, http://www.pjm-miso.com/committees/working-groups/rrawg/downloads/20090116-item-03-changes-and-dates.pdf

- In order to reduce the number of non-viable projects and multiple interconnection requests submitted for speculative purposes, PJM began requiring deposits that increase each month during the queue and include both a refundable and a non-refundable element.
- In the past, PJM often received a large number of interconnection requests at the end of the queue period, which significantly contributed to the backlog in the queue. Under the revised rules, the timeframe allowed for holding a scoping meeting to initiate interconnection studies decreases the later a request is entered into the queue, thus providing an incentive to submit interconnection requests earlier in the queue cycle.
- Interconnection requests must now specify a primary and a secondary interconnection point. In the past, interconnection customers could choose two points of interconnection, and PJM was required to conduct two simultaneous sets of studies for each of the two locations.
- PJM revised the methodology of allocating the costs of required transmission upgrades. In the past, cost allocation was determined incrementally, based on the position in the queue. As a result, PJM had to perform repeated studies whenever an earlier project in the queue was withdrawn. Under the new method, PJM performs studies in clusters and analyzes all projects in a single queue.
- Other changes include requiring timelier submittal of necessary data, applying commercial probability of success ratios at various stages of the interconnection process, and requiring proof of site control.

While the interconnection process continues to be a source of uncertainty for generation development, particularly with respect to interconnection costs, PJM has made significant progress streamlining the process. Queue requests are now processed in a timelier manner. As shown in Table 13 below, 89% of Feasibility Studies were issued on time in 2010.[57] This is a significant improvement since 2007, when only 53% of Feasibility Studies were completed on time. Similar improvements have occurred with respect to System Impact Studies: while in 2008 only 29% have been completed on time, that proportion had increased to 77% as of 2010.

Table 13
Percentage of Interconnection Studies Completed On Time

Year	Feasibility Study	System Impact Study
2007	53%	44%
2008	70%	29%
2009	83%	51%
2010	89%	77%

Source : PJM

PJM's corporate goal for 2011 is to complete all studies backlogged as of January 1, 2011 by the beginning of 2012, and to reduce the backlog of System Impact and Feasibility Studies below

57 These studies represent two of the main steps in the interconnection process.

25% and 10%, respectively.[58] To address the remaining challenges related to the interconnection process, PJM formed the Interconnection Process Senior Task Force ("IPSTF") in February 2011. IPSTF's goal is to develop enhancements that would lead to more consistent and realistic interconnection cost estimates, more timely completion of interconnection studies, and greater transparency of the overall interconnection process.

E. Summary of Findings from Analyses of Auction Results

After completing auctions for eight delivery years under RPM, the market has thus far achieved its design objective of procuring sufficient capacity to meet reliability requirements. A total of 28.4 GW (ICAP) of gross additions and 13.1 GW of net additions have been added or committed under RPM auctions (excluding FRR and RTO expansions), exceeding reliability requirements. The gross committed additions are from 11.8 GW of new demand resources, 6.9 GW of increases in net imports, 4.8 GW of new generation, 4.1 GW of uprates, and 0.8 GW of reactivations. These additions were offset by 15.3 GW of gross capacity reductions, including 5.0 GW of retirements, 2.7 GW of derates, 6.8 GW of capacity removed from auctions for FRR, and 0.7 GW of generation excused from auctions.

On both an RTO and LDA-specific basis, sufficient capacity was procured under RPM to meet or exceed the reliability targets, with no large or persistent capacity deficits observed to date. Procurement below the reliability target in eastern LDAs during the first years under RPM was related to the overall tight supply conditions that existed prior to the introduction of RPM. All LDAs also had additional uncleared offers from incremental capacity supplies in most years that could have been procured at higher prices had those supplies been needed for reliability.

To date, RPM has performed well in the face of the proposed EPA HAP regulation, which will take effect during the 2014/15 delivery year and impose large compliance costs on many coal generators and force others to retire. Despite this substantial challenge to resource adequacy, capacity procurement through the 2014/15 delivery year exceeded the target procurement on an RTO-wide level as well as in all modeled LDAs. Due to environmental regulations and an overall capacity surplus, 12.8 GW (ICAP) of existing capacity, mostly coal, is currently uncommitted for resource adequacy in 2014/15, having been withdrawn from RPM auctions or failed to clear the BRA. Many of these generators would need to invest in environmental upgrades to continue operating in 2014/15 and will likely retire if they do not clear in upcoming auctions.

Clearing prices in the base auctions have been consistent with market fundamentals—clearing at levels below Net CONE during times and locations of capacity excess and above Net CONE at times and locations of relative scarcity. Large quantities of relatively low-cost capacity additions from DR, uprates, and increased net imports have kept prices below Net CONE most of the time in most locations. These increases in low-cost resources have reduced system costs by postponing the need for expensive additions of new generation and allowing for the retirement of uneconomic existing capacity. Furthermore, the supply curves have become more gradual due to the incorporation of substantial quantities of DR and the three-year forward period of RPM, which will contribute to increase price stability in the future. To date, base auction prices have

58 For example, see "Interconnection Update," February 16, 2011. http://www.pjm.com/~/media/committees-groups/committees/mrc/20110216/20110216-item-06a-interconnection-update.ashx

been somewhat volatile, with substantial price changes from year to year caused by market fundamentals, changes in market rules, changes to which LDAs were modeled, and changes in administrative auction parameters.

Clearing prices in the incremental auctions prior to the 2012/13 redesign demonstrated a pattern of being persistently far below base auction clearing prices. However, as discussed in Section II.B, the incremental auction design has been substantially improved starting with the 2012/13 delivery year. Initial results show that the new design resulted in prices that are more consistent with base auction prices, though more experience with the new design is needed to fully understand how it will function over time.

III. STAKEHOLDER COMMENTS AND DISCUSSION OF KEY THEMES

As an initial task in our RPM performance review, we gathered input on which aspects of RPM are working well and which should be improved. We gathered input from five stakeholder sectors, financial analysts, public utility commissions, and the Independent Market Monitor.

Stakeholder Sectors — We conducted sector interviews with transmission owners, generation owners, electric distributors, end use customers, and other suppliers. Stakeholders have also provided 13 sets of written comments and several have contacted us for individual follow-up interviews.

***Financial Analysts* —** We individually interviewed financial analysts covering RPM from CitiGroup, UBS, and Goldman Sachs.

State Utility Commissions — We contacted members of each public utility commission of 13 states and the District of Columbia. In response, we received input in interviews or written comments from eight commissions (Delaware, the District of Columbia, New Jersey, Ohio, North Carolina, Pennsylvania, Michigan, Virginia). The remaining six commissions either declined to comment (Maryland and Kentucky) or did not respond (West Virginia, Tennessee, Illinois, and Indiana).

***Independent Market Monitor* —** We reviewed the substantial body of evidence and analysis on RPM that has been developed by the independent market monitor (IMM), including the state of the market reports, auction reports, and comments in FERC and state proceedings.[59] We have also had several conference calls and exchanges with the IMM to discuss our recommendations and analysis related to specific elements of the RPM design.

We summarize here stakeholders' comments and identify the key themes that have emerged, which we used to focus our analysis on the topics most important to stakeholders. We respond to each of the most prominent themes here and explain how we have addressed each of them in the body of this report.

59 See reports posted at www.monitoringanalytics.com.

A. Summary of Stakeholder Comments

A detailed summary of stakeholder comments is included in the Appendix. We summarize here the topics that were stressed as the most important issues that we should consider in our performance review.

Level of RPM Clearing Prices — End use customers and state commissions in eastern PJM stated that RPM prices were too high and may not be commensurate with the value of reliability to customers. Some commissioners further stated that existing generation and demand resources should be paid lower prices than new generation. Generation and transmission owners stated that eastern prices are not high enough to attract new investments, while western prices are too low and are creating retirement incentives. Other suppliers noted that incremental auction prices are biased to be much lower than BRA prices.

Uncertainty of RPM Prices **—** All stakeholder sectors stated that RPM prices are volatile and too difficult to predict. However, generation and transmission owners also indicated that RPM price signals are more stable and locationally appropriate compared to prices in PJM's previous daily capacity market. Financial analysts stated that investors discount the value of RPM revenues due to the uncertainty and that more transparency is needed in the supply curve and administrative calculations to allow for improved projections that would better support investment decisions.

Capacity Additions and Retention **—** Concerns about a lack of new generation entry were expressed by eastern state commissions, electric distributors, end use customers, some generators, and some transmission owners. Other generators and transmission owners stated that fears of a capacity shortage were overstated and that new investments can be financed when prices are high enough, although more capacity price stability and longer-term hedging mechanisms would help. Generation and transmission owners point out that the EPA HAP regulation will create a resource adequacy challenge and force many plants into retirement.

Reliability Standards and Customer Reliability Requirements **—** End use customers and state commissions stated their belief that PJM has an institutional bias to overstate load forecast and reliability requirements, causing excess costs to customers. They further question whether the 1-in-10 system reliability standard and in particular the 1-in-25 LDA transmission-contingent reliability standard are appropriate, suggesting that they represent too much reliability given the high cost of capacity. End use customers are further concerned about significant quantity risks that they face due to substantial uncertainties about their ultimate Peak Load Contribution ("PLC") and the slope of the VRR curve, which also makes it difficult and risky for individual large end-users to directly participate in RPM as a demand-response resource.

Cost of New Entry **—** End use customers stated that CONE should be based on the lowest net cost technology in each region. Generation and transmission owners argued that CONE is understated because of cost estimates that are too low for natural gas interconnections, transmission interconnections, labor, taxes, and financing costs.

Energy Market and E&AS Offset **—** Electric distributors, other suppliers, transmission owners, generation owners, and state commissions noted that they support greater scarcity pricing in the energy market. Other suppliers and electric distributors stated that the current energy market price cap of $1,000/MWh is too low and creates a disadvantage for DR in the capacity market, especially as an annual resource, because they may value the energy at a higher rate. Generation and transmission owners stated that there should be no capacity payment reductions due to scarcity pricing other than incorporating scarcity prices into the E&AS offset as is currently done. End use customers stated that the lag in the historical E&AS offset will be especially problematic during the transition to scarcity pricing. Other suppliers and financial analysts stated that the E&AS offset should be forward looking, while transmission owners stated that a forward-looking offset would be prone to error and dispute. Generation owners, other suppliers, and transmission owners stated that the calculated E&AS offset was too high given the current low gas prices and energy margins, the use of real-time rather than day-ahead prices, and an optimistic dispatch algorithm.

VRR Curve and FRR Alternative — Generation owners, other suppliers, and transmission owners stated that the VRR curve is too steep and causes price volatility. State commissions stated that the 1% adjustment to point "b" on the curve creates a bias toward over-procurement. State commissions and transmission owners stated that the FRR alternative is valuable but that restrictions on capacity sales and switching to or from FRR should be relaxed.

Demand-Side Resources and Resource Comparability — Generation and transmission owners expressed the concern that lax performance and qualification standards threaten the quality of the capacity procured from demand resources. They further stated that demand resources have fewer obligations than does generation supply, including the lack of a must-offer requirement in the energy market. End-use customers and other suppliers noted that demand resources are disadvantaged due to high credit requirements and risks in the three-year forward BRA. The independent market monitor suggested that all resources should have the same obligations and the same definition of capacity.

2.5% Short-Term Resource Procurement Target — The IMM, generation owners, and transmission owners recommended that the 2.5% "holdback" be eliminated because it artificially suppresses BRA prices. Electric distributors stated that the 2.5% holdback should be maintained, while other suppliers noted that the holdback is too small and artificially inflates BRA prices while suppressing incremental auction prices. End-use customers stated that, with only one incremental auction since the implementation of the holdback, there was not enough information to evaluate the appropriate size of the STRPT amount.

Transmission-Related Issues — Comments on transmission issues did not generally differ across sectors, although multiple views were often expressed within each sector. Stakeholders identified CETL as an important parameter that is volatile and not transparent. Most sectors suggested that major transmission projects should not be cancelled so readily and that RTEP should more fully consider economic criteria in addition to reliability criteria. Stakeholders indicated that greater consistency is needed between RTEP and RPM, including making sure that uncleared RPM resources are not modeled in RTEP. Some stakeholders argued that additional LDAs should be modeled including part of Dominion or APS-South, or that all 23 LDAs should be modeled. Other stakeholders argued that too many LDAs already exist, that LDA are modeled even when no longer constrained, and that only 2 or 3 LDA may be necessary. Transmission and generation owners suggested that the BRA should be conducted on a 5-year forward basis to coincide with RTEP planning horizons.

***Market Monitoring and Mitigation* —** Electric distributors and state commissions stressed that new MOPR provisions will have the large unintended consequences of eliminating self-supply and creating excess risks for new generation developments. Financial analysts, generation owners, and transmission owners emphasized that MOPR must be strong enough to prevent market manipulation through state-sponsored capacity additions. The independent market monitor is also concerned about out-of-market capacity additions, but recommends an exemption for procurement through competitive, non-discriminatory processes. End use customers noted that they are concerned that bid adders allowed under the avoidable project investment rate ("APIR") may be too high and allow for economic withholding, which may be a particular concern as suppliers are forced to comply with EPA's HAP regulations.

***Extending Forward Certainty* —** Stakeholders representing both buyers and suppliers of capacity noted a lack of sufficient long-term contracting. Electric distributors, end-use customers, and generation owners attributed the lack of bilateral long-term contracting to state retail choice and standard offer service programs. Generation owners noted that there is a lack of buyers for long-term bilateral contracts with durations of more than 3-5 years, while electric distributors have stated that they are unable to find suppliers willing to enter into bundled long-term energy and capacity contracts. All stakeholder sectors suggested options for extending forward certainty and providing hedging options under RPM. These options included a continuously-clearing over-the-counter ("OTC") market for capacity and longer-term procurement through multiple forward or strip auctions. Generation and transmission owners were divided on NEPA, with some stating that the mechanism is discriminatory and should be eliminated and others stating that it should be expanded to existing generation, extended in duration, or applied outside the LDAs. Financial analysts stated that extending NEPA would benefit project financing.

We used these stakeholder comments and concerns to focus our performance review on the topics of highest importance. We recognize that many of these comments represent conflicting viewpoints between sectors and sometimes even within individual sectors, but have attempted to evaluate all of the associated arguments. Stakeholders identified concerns with a number of specific design elements, but we also identified a few key themes of several inter-related issues. To help clarify some of these more general concerns, we discuss them in the remainder of this section and note if we have analyzed and addressed them more fully later in this report.

B. Capacity Price Volatility and Uncertainty

The greatest concern expressed by stakeholders from all sectors is that capacity prices under RPM are highly volatile and very difficult to predict. Stakeholders express that this uncertainty imposes additional costs and creates difficulty hedging and making investment decisions. Some stakeholders have expressed a lack of transparency about the underlying causes of major price changes, or have attributed various price changes to causes that they view as arbitrary or inefficient.

In response to these stakeholder concerns, we have reviewed all substantial price changes observed under RPM to date. We have identified and documented the major drivers behind the observed price changes as explained in Section II.A (for the BRA) and Section II.B (for the incremental auctions) of our report. These main drivers of capacity price uncertainty fall into three categories: (1) underlying market fundamentals; (2) RPM design elements that have previously caused significant price adjustments; and (3) current RPM design elements and related administrative parameters that cause significant price uncertainty.

Ideally, only market fundamentals should drive capacity prices or create price uncertainty, factors which should not be dampened by RPM design or administrative intervention. In fact, administrative and regulatory uncertainty, while impossible to eliminate, should be minimized to the extent practical. We briefly discuss each type of uncertainty in the remainder of in this section and more fully address options to mitigate excess price risks related to administrative factors in our discussion of specific RPM design elements.

1. Market Fundamentals

Several changes in underlying market fundamentals have been major drivers of price changes and uncertainty:

- The emergence of surplus capacity in the unconstrained RTO, and to a lesser extent in the LDAs, that has depressed capacity prices to levels well below Net CONE;
- Transmission constraints between the unconstrained RTO and the LDAs have limited the ability to import low-cost supply into eastern PJM and caused large locational price separations in some years;
- Steep supply curves during the first RPM auctions caused prices to be sensitive to small changes in resource demand. The steep supply curves were primarily the result of a short forward period (*i.e.*, less than 2 years) between the auction and delivery year for the first several RPM auctions. This limited the potential quantity of new capacity that could participate in the auctions and be available in time for the delivery year. Supply curves have since flattened significantly, due to the longer forward period and a substantial influx of DR resources with offers covering a wide range of prices;
- Significant growth in low-cost DR resources has contributed to lower prices;
- The economic recession has reduced the outlook for electric demand starting with PJM's 2009 load forecast used for the 2012/13 BRA; and
- Environmental upgrades that will be required by the EPA HAP regulation for operation sometime in during the 2014/15 delivery year have caused prices to rise substantially in the unconstrained RTO in the most recent BRA.

All price uncertainty and volatility will tend to increase risks and therefore increase costs.[60] However, to the extent that these risks consistent with uncertainty in underlying market fundamentals, they are important to ensure the efficient functioning of the market and should not

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60 Increased risks of all kinds result in a higher expected required return on investments. See, for example, the empirical finding that "a doubling of industry-wide uncertainty raises the required rate of return on new capital by about 20 percent," by Caballero and Pindyck (1996). For another example, see the empirical finding that increased volatility in cash flows increases the cost of debt and decreases the likelihood of making investments from Minton and Schrand (1999), pp. 423-26.

be suppressed artificially. Stabilizing RPM prices despite underlying uncertainties in market fundamentals would not eliminate the associated risks, but would simply shift the costs associated with these risks from suppliers to customers. For example, a traditional regulatory regime would reduce a generation supplier's development costs by ensuring cost recovery for all prudent investments, but this does not eliminate the fundamental risk that an event like a major recession could render the investment uneconomic. In a traditionally regulated environment, the out-of-market costs of the uneconomic investment would be borne by customers paying for unneeded supplies. In a restructured, competitive wholesale power market like PJM, however, the suppliers bear the market risk of losing money on uneconomic investments.

One of the key benefits of competitive power markets, including the PJM's capacity market, is that market prices can move with market fundamentals and create incentives to respond. Unexpectedly high prices will create a strong incentive for suppliers to quickly develop more demand response and speed the completion of generation under construction. Similarly, unexpectedly low prices will signal that expensive existing generation should be retired and new generation projects should be delayed. Ensuring that these incentives are delivered accurately to marginal resources through capacity prices will allow reserve margins to remain near the target levels, preventing both severe shortages and costly excess of supply. Private investors facing the risks associated with these market fundamentals will carefully assess the likelihood that their investment may become uneconomic and incorporate that possibility into their investment decisions.

Market rules or administrative interventions that dampen these price signals will tend to create an inefficient disconnect between market fundamentals and incentives.[61] For this reason, we are skeptical of some options for reducing RPM price uncertainty, including the further flattening of the VRR curve (as discussed in Section V) or expanding the New Entry Pricing Adjustment (NEPA) mechanism (as discussed in Section VI.F). However, while we recommend that RPM clearing prices should be allowed to continue to reflect changing and sometimes volatile market conditions, this does not mean that market participants should not have opportunities to hedge against these risks. These hedges may take the form of asset ownership or bilateral contracts (as discussed further in Section III.C) or may include other options for facilitating long-term hedging options through RPM design (as discussed further in Section VI.F).

2. Previously-Changed RPM Design Elements

Some of the RPM prices and price changes observed to date were caused by unintended consequences of market design elements that have since been modified. These previously-addressed modifications to RPM design elements include:

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[61] For example, the price floor in ISO-NE's forward capacity market (FCM) has created substantial price stability in that prices have cleared at the floor for the first five forward capacity auctions. However, this stability has come at the cost of exacerbating an over-supply situation by preventing expensive existing generation from retiring and attracting substantial new supplies into the market. In fact, the first FCA for 2010/11 cleared at the floor with 1,772 MW of excess capacity, while subsequent auctions cleared at the price floor with increasing excesses of up to 5,374 MW for 2013/14 before dropping to somewhat lower levels for 2014/15 in the face of the EPA HAP regulation. See ISO-NE (2011a) and (2011b), p. 106.

- When RPM was implemented, a large portion of demand-side resources was interruptible load for reliability (ILR), which was accounted for outside the RPM auctions. This meant that auction prices initially failed to reflect the substantial growth in demand-side resources. Incorporating these resources into the auctions starting in the 2012/13 BRA allowed auction prices to reflect these supply fundamentals more accurately, which resulted in a large price drop (mostly in the unconstrained RTO) compared to the previous years.[62]

- For the first five delivery years, the rules governing which LDAs would be modeled in RPM auctions were more restrictive. This resulted in frequent changes in which LDAs were modeled and were allowed separate from the RTO and other LDAs in terms of its clearing price. In some cases this prevented price separation that would have been necessary to reflect market fundamentals as discussed in Section II.A. A set of rule changes implemented in time for the 2012/13 BRA ensured that certain LDAs were modeled, which allowed prices to separate. Going forward, these rule changes will create more stability in which LDAs are modeled and will allow LDAs that might price separate to be modeled more often.[63]

The unintended consequences associated with these RPM design elements resulted in a failure to fully account for demand-side resources and transmission constraints, which led to higher auction prices. Adjusting these design elements caused some of the observed price changes, but resulted in an improved market design with better price signals going forward. We keep these previous changes in RPM design elements in mind as we evaluate related aspects of RPM, because it will be valuable to avoid similar unintended consequences in the future. In particular, we examine the importance of modeling additional LDAs that might price separate in the future (Section VI.A) and examine the potential future implications of incorporating multiple demand response products (in Section VI.C).

3. Current RPM Design Elements and Administrative Parameters

While some market design elements (or adjustments to them) have created price volatility in the past, Stakeholder groups have identified several market design and administrative parameters that are quite uncertain and, as a result, continue to create significant uncertainty in RPM prices beyond changes in market fundamentals. We have identified two sets of design elements and administrative parameters that result in significant capacity price uncertainty:

- *Volatility and uncertainty in CETL*, which determines the quantity of capacity that can be imported into each LDA. Some changes in CETL are driven by changing plans for major transmission upgrades. Other changes are driven by modeling sensitivity to detailed assumptions including load distribution and the forecast of generating units are expected to be online or retired.

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62 See PJM (2011d), sections 4.3.5 and 9.3.6.

63 Prior to 2012/13, LDAs were modeled only if their Capacity Emergency Transfer Objective ("CETO") was ≤ 1.05 CETL. Starting with 2012/13 more LDAs will be modeled, including: (1) MAAC, SWMAAC, and EMAAC which will always be modeled; (2) LDAs with CETO ≤ 1.15 CETL; (3) LDAs that have price separated in any of the three previous BRAs; and (4) any LDAs that PJM expects may price separate. See PJM (2011d), pp. 11-12.

- *Changes in the load forecast and locational reliability requirements*. Some changes in the load forecast and associated reliability requirements are driven by market fundamentals including the recent economic recession. However, other changes may be related to forecasting uncertainty or related changes in administrative assumptions.

These market design issues are primarily related to the difficulty of determining administrative parameters that are inherently uncertain but that have a large price impact on auction prices. One reason that these parameters are so uncertain is that they are related to future market fundamentals that cannot be accurately predicted by market participants or by PJM. However, some of the uncertainty and the impact that these administrative uncertainties have on market prices can be reduced in several ways, including: (1) improving market participants understanding of the uncertainty in these parameters; (2) increasing transparency by providing and more frequently updating the long-term outlook for administrative parameters; (3) reducing the sensitivity of final RPM auction parameters to modeling assumptions; and (4) limiting the impact of changes in administrative calculations on auction results.

We examine several of these options in Section VI.B with respect to load forecasting and reliability requirements and in Section VI.A with respect to CETL and transmission upgrades.

C. THE LACK OF LONG-TERM PPAS TO SUPPORT NEW PLANT FINANCING

A number of stakeholders have expressed concerns related to an apparent lack of long-term contracting that could support the financing of new generation additions in eastern PJM:

- Regulators in eastern PJM expressed the concern that there is a dearth of new power plant construction under RPM.
- Some generation developers similarly noted that three-year forward RPM prices effective for only one delivery year do not support the financing of new generation projects. They suggest that prices would need to be locked in for up to 10 years or more to support financing of new generation projects.64
- Financial industry participants similarly note that RPM does not support the financing of new generation, which would require revenue certainty over longer periods of possibly 10 years or more.65
- Stakeholders universally reported a current lack of long-term bilateral contracting of more than three to five years forward to provide price certainty beyond that offered directly by RPM. Generation developers stressed that buyers are unwilling to enter long-term contracts, while stakeholders from the public power companies indicated a strong interest in signing long-term contracts, but stated that they were unable to find willing suppliers.

The concerns that longer-term pricing arrangements are needed for financing new plants are seemingly inconsistent with public power stakeholders' concern that suppliers were generally

[64] We note that this view is not uniform in the generation owner sector.

[65] See also letters from Credit Argicole and Union Bank attached to LS Power Associate Comments on New Jersey Electric Power and Capacity Needs, Submitted in State of New Jersey Board of Public Utilities, Docket No. EO 09110920, July 2, 2011.

unwilling to offer long-term contracts. We believe this apparent inconsistency of concerns is explained largely by current market fundamentals.

The main reason for the low activity of new power plant construction in eastern PJM is the fact that new plants are not needed for several more years due to a combination of low load growth on the demand side of the market, and lower cost supply options such as deferred retirements, transmission upgrades, demand response penetration, and upgrades to existing units. That is, RPM has been able to retain or attract the lowest-cost set of resources to maintain resource adequacy. In other words, the lack of feasible long-term contract offers for new generation is explained by market prices for capacity that are below the cost of new plants.

These market fundamentals also explain the lack of long-term contracts with existing generation. Suppliers of existing capacity are unwilling to enter long-term contracts at low current prices because they expect prices will rise. At the same time, buyers are unwilling to pay higher prices or even the cost of new generation when there are less expensive options currently available in the market. It is likely, however, that interest in longer-term contracting will increase as excess capacity diminishes and capacity market prices rise to the cost of new generation on average over many years.

It is also possible, however, that secondary factors create contracting barriers, such as the structure of default service procurement in retail access states. If these barriers turn out to be significant—which is difficult to determine under current market conditions—modifying how default service procurement is regulated at the state level may be the most effective way to address these barriers. If that is not feasible, it may be worth considering longer-term pricing options under RPM. We stress caution in considering these options, however, because we believe that it should not be the role of an RTO to offer or force long-term contracting for capacity resources when load-serving entities do not see the risk management benefit of entering into such contracts bilaterally. Nor would an RTO be able to readily determine the amount of long-term contracting or contract terms that optimally balance risks. Mandating too much long-term contracting would inefficiently expose suppliers to delivery and credit risks while buyers are exposed to larger risk premiums and the potential for stranded costs.

It is also likely that the need for and reliance on long-term power purchase agreements (PPAs) and project financing will diminish as the industry evolves and an increasing share of new plants are developed by larger, partially vertically-integrated companies with load serving responsibilities, a portfolio of merchant generation, and sufficiently strong balance sheets to finance the needed investments. We discuss each of these points in more detail in the remainder of this section.

1. The Role of Current Market Fundamentals

It is correct that relatively few new power plants have been built in eastern PJM since RPM has been implemented. However, as we have explained in Section II, it is not true that no new generation has been built in eastern PJM. Even without considering capacity uprates of existing plants (2,210 MW), reactivations (360 MW), export reductions (930 MW), or increased demand response (6,550 MW), approximately 2,040 MW of new generation capacity has been committed in the MAAC region under RPM, and another 650 MW of new generation offers have been submitted but failed to clear because sufficient capacity has been offered at prices below the cost of new generation.[66]

Nevertheless, the relatively modest level of new generation construction in eastern PJM has not led to resource adequacy shortfalls, as some stakeholders believe. Reserve margins have remained at or above target levels, due to the combination of entry by these new generation units, combined with demand response resources, upgrades to existing capacity, deferred retirements, planned transmission upgrades, and the economic slowdown. Moreover, RPM has maintained resource adequacy at prices that have generally remained below the cost of new generating plants.

It is also correct that market prices for capacity in eastern PJM have been significantly higher than in the remainder of PJM in most years. However, even these eastern PJM capacity prices have generally remained below the cost of new plants in the recent BRAs. Prices will remain below the cost of new plants until new generation is needed and capacity prices rise to clear new offers.

We believe the underlying fact that new generation is simply not cost-competitive with lower cost options such as uprates, deferred retirements, and demand response under these market fundamentals is the primary reason that there has not been more new construction of generating plants in eastern PJM. That capacity prices will remain below the cost of new plants through 2014/15 and possibly for several more years is likely also the primary reason that some developers' new generation projects cannot be financed without long-term contracts. Current market conditions do not support long-term contracts at prices high enough to finance new plants because rational buyers prefer to satisfy their capacity requirements at market prices that are below the contract cost of a new plant.

Under these market conditions, when few or no new plants are needed, the only way to finance additional new generation would be through above-market long-term contracts. Such above-market contracts have recently been offered through a New Jersey legislative mandate, which procured capacity for three new plants under fixed-price 15-year contracts whose costs are not public but that are estimated at approximately $270-350/MW-day.[67] In comparison, RPM prices in New Jersey have been much lower at $136-225/MW-day for annual resources in the most recent BRA.

In short, the lack of long-term contracts and financing for new plant construction is a consequence of the fact that investments in new generation are at present inherently unprofitable and not part of the least-cost solution to resource adequacy. Currently, new generation is not a cost effective way to meet anticipated load growth. Under these circumstances we do not expect a well-functioning market to reward investments in new generation. In other words, the absence of new construction is a sign that the market is working.

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[66] Reported in ICAP. Note that most new generation offers that have failed to clear in one auction have subsequently offered and cleared in later auctions, from PJM (2011a).

[67] See

Table **1** for auction prices. Approximate New Jersey procurement prices were calculated by the New Jersey EDCs (2011), pp. 8-9.

Current market fundamentals are also the likely reason that public power entities looking for long-term capacity contracts have not found willing suppliers. First, given that capacity prices may remain below the cost of new plants for a number of years, buyers interested in long-term contracts will not be willing to sign long-term contracts priced at the full cost of new power plants. Thus, developers of new power plants will be unwilling to offer long-term contracts at prices acceptable to buyers. Second, even owners of existing generating capacity will be unwilling to sign long-term contracts at prices equal to current market prices if they anticipate that RPM prices increase over time. It is likely, however, that buyers' and existing generators' interest in longer-term contracting will increase as excess capacity diminishes and capacity market prices rise to the cost of new generation over the next several years.

2. Availability of Financing

As discussed, current market fundamentals in PJM do not generally support the entry of new plants. Thus, without a need for new plants, financing for such plants will not be available unless supported by (above-market) long-term contracts.[68] However, this does not mean that financing is not available for sound investments at costs that are consistent with market fundamentals. In fact, there has been keen interest in the acquisition of power plants in eastern PJM, and major recent transactions have documented the availability of financing for investments in merchant power plants.

A notable example in eastern PJM is Calpine's 2010 acquisition of 4,490 MW of Conectiv Energy power plants in eastern PJM from Pepco Holdings Inc. ("PHI").[69] The $1.63 billion purchase, which included some existing forward capacity and energy sales commitments as well as a six-year tolling agreement with Constellation Power for the Delta power plant that was under construction at the time, was financed with $1.3 billion of seven-year debt and $100 million of three-year debt.

3. The Role and Implications of "Project Finance"

Generation developers' frequent preference to build new power plants through highly-leveraged "project finance" arrangements appears to be another major driver behind their interest in long-term power purchase agreements. Project finance refers to the use of project-specific debt, also called "non-recourse" debt that is not backed by a guarantee from a larger parent company. Project finance is often the only available option for small project development companies that do not have a significant portfolio of other assets or for companies with weak balance sheets and poor credit ratings.

Such non-recourse debt is secured solely by the revenues and asset value of the specific power plant. It is more risky to the lender and consequently more expensive than corporate debt that is secured by the more diversified revenues and assets of the parent company. However, while more expensive than corporate debt, non-recourse debt is still attractive to developers because it

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68 See also B. Chin, "Capacity Issues Technical Conference: State of New Jersey," Citi Investment Research, June 24, 2010, noting that "in our view, energy/capacity markets are providing a signal that capital should not be deployed to [new] generation at this time, unless subsidies are enacted."

69 For example, see Calpine (2010).

is less expensive than equity and reduces the potential liability to the parent company if the project proves to be a bad investment.

To reduce financing costs, project developers will similarly prefer to "lever up" their investments by using higher levels of debt and less equity. However, such reductions in financing costs are possible only if project risks are reduced through long-term power purchase agreements that shift market risks from the generation owner to the buyer of the power. In fact, by assuming project risks through a long-term contract, the buyer is reducing (and essentially subsidizing) the financing cost of the new plant. Financing projects with high levels of debt (*e.g.*, 70 to 80% debt) can reduce the levelized annual investment cost of a project by 10% to 20% compared to merchant plant financing, which may allow financing with only 30% to 50% non-recourse debt (backed solely by the project) or 50% to 60% corporate debt (backed by the entire parent company).

In a well-functioning market, a range of financing arrangements will exist under which buyers can assume risks under a long-term contract (that support for more highly leveraged financing by the developers) or developers can assume these risks (which requires financing with more equity) depending on risk sharing preferences and the financial conditions of the counterparties. However, it is not desirable to enable uneconomic investments in new generation through long-term PPAs when those developments are more costly or more risky than capacity from market-based resources, including from existing generation supplies and demand response.

4. The Role of Default Service Procurement in Retail Access States

We believe that longer-term contracting will increase as capacity market prices reach and sometimes exceed the cost of new generation. It is conceivable, however, that market or regulatory barriers could prevent an outcome in which an efficient level of longer-term contracting is achieved, although we do not presuppose to know what that efficient level of long-term contracting might be.

The current nature and regulation of retail services in restructured states may represent such a barrier that might inhibit reaching optimal levels of long-term capacity contracting in PJM. This is because a significant portion of retail load is supplied under regulated "default service" arranged by electric distribution companies ("EDCs") and overseen by the utility commissions. In restructured eastern PJM states, such as New Jersey and Maryland, the EDCs are required to procure bundled energy and capacity supplies for these default service obligations. The contracts for such default service procurement generally have durations of three years or less. This sole reliance on short- or intermediate-term contracts under state-regulated default service procurement appears to deviate significantly from the procurement and risk management practices of large competitive retail service providers.

Competitive retail service providers, including those in PJM, appear to secure a meaningful portion of their supplies through long-term contracts or even the acquisition of generating assets. Such actions are designed to counter the effects of perceived broken linkages between competitive retail and wholesale markets by reducing the transaction costs of securing long-term contracts and effectively vertically re-integrating load serving responsibilities with merchant generation. For example, Constellation's NewEnergy retail supply business obtains energy from a portfolio of various sources, including its own generation assets, contractually-controlled generation assets, exchange-traded bilateral power purchase agreements, unit-contingent power purchases from generation companies, tolling contracts with generation companies, and spot purchases from the regional power markets.[70] This portfolio balances retail sales contracts that are reported to extend from one to ten years and beyond, although these will generally not be exactly matched by long-term capacity procurement contracts.[71] Constellation Energy explicitly stated that its strategic retail-service-operations objective is to buy generation assets in regions where the company does not have a significant generation presence and enter into longer-term agreements with merchant generators.[72] In fact, this objective was a primary reason for Constellation's purchase of generating plants in Texas as well as its recent acquisition of 2,950 MW of generating plants in ISO-NE, which "improved [Constellation's] net load to generation ratio to approximately 55 percent."[73] Direct Energy, another retail service provider, appears to have started pursuing a similar strategy through long-term contracting power from generation suppliers, buying physical generation assets, and even acquiring natural gas production, storage and transportation.[74] Similarly, NRG's recently announced acquisition of Energy Plus holdings was explained as an effort to "expand its retail marketing presence in the Northeast and Mid-Atlantic" to give the company "more of a retail presence to offset its generation assets in periods when wholesale power prices are depressed."[75] NRG's announcement also marked another retail acquisition following Constellation Energy Group's purchase of StarTex Power and its planned acquisition of MXenergy, and Direct Energy Services' purchase of Gateway Energy Services.[76]

We have not analyzed what fraction of total retail load should be supplied through long-term contracts or physical plant ownership. Such decisions will depend upon a company's tolerance for risk and expectations regarding future market conditions. While long-term contracts and physical plant ownership will stabilize procurement costs, they also create the risk that costs will be above market. However we believe it is possible that the most efficient amount and duration of long-term contracting may exceed the amount realized for load under default service procurement. We view this potential concern over whether default service creates a barrier to efficient contracting primarily as a matter for state commissions and state legislatures to examine in the context of retail choice and default service regulations. The best way to realize an efficient level of long-term contracting and asset ownership among retail providers might be for the states to reduce their reliance on default service. This would allow increased interaction between retail service providers and customers that would allow market participants to determine the most efficient retail supply portfolio. Reduced reliance on default service, for example, exists in Texas where most retail customers are served by competitive suppliers after default service was eliminated in 2007 (although a provider of last resort service is still available to customers who lose their competitive service providers).[77] A second option that states could pursue would be to review default service procurement practices to determine the extent to which longer-term

70 See Constellation's 2010 10-K filing in Constellation (2011), Part 1, Item 1, pp. 4-5.

71 *Id.*

72 See Constellation (2010), pp. 29 and 60; Morningstar (2010).

73 For example, see Constellation (2010).

74 Direct Energy (2011).

75 Megawatt Daily, "NRG to buy Energy Plus Holdings for $190 mil," August 17, 2011.

76 *Id.*

77 Kiesling and Kleit (2009), Chapter 8.

contracts (procured on a non-discriminatory basis from existing or new resources) should be part of default service procurement.

Only if states fail to pursue these options and generation investment lags even as market prices reach or exceed Net CONE, it may be necessary for PJM to introduce mandatory long-term procurement of capacity into the RPM construct. However, we consider this to be a far less desirable option and would recommend pursuing this option only if (1) it becomes clear that a review and revision of default service procurement is unlikely, and (2) it can be determined with sufficient confidence that longer-term contracts through RPM-based resource procurement will actually be needed to assure resource adequacy at reasonable costs. We examine this option along with several alternatives more fully in Section VI.F.

5. Does the Electric Power Industry Need Long-Term Contracts?

There is a perception that new generation cannot be built without long-term PPAs or close to 10 years or more. As discussed above, this perception is largely created by current low-priced market fundamentals and the preference among developers to lay off risks onto contract counterparties. Reliance on long-term contracts is also rooted in the regulated past of the industry (including Qualifying Facilities under PURPA). However, a number of observations about customer preferences and contracting practices in other capital intensive industries suggest that widespread perceptions may overstate the need for long-term contracting as the industry evolves.

First, most retail customers are unwilling to commit to long-term contracts. The reluctance is not unique to restructured electric power markets. This is also the case for most energy commodities sold in retail markets, including commodities with even higher price uncertainty, such as gasoline. If contracts are signed in other retail market segments, they rarely go beyond the next season (*e.g.*, heating oil), or the next two years (mobile telecom service). In fact, long-term contracts between retail customers and suppliers are uncommon even in the most risky and capital intensive portions of the energy industry (such as oil and natural gas exploration), despite the unpredictable nature of risks (such as oil price movements based on a wide range of geopolitical influences, including cartel behavior).

Second, other capital-intensive industries with significant price risks generally require that investments are backed by companies with sufficient equity. However, such "balance sheet financing" of major investments is less common in the electric power industry.[78] While numerous examples of balance-sheet financing and generation investments without long-term PPAs or other long-term price hedges exist (including merchant wind power development),

[78] The use of balance sheet financing does not mean that medium- or long-term contracts are eliminated for these projects. Rather, it simply means that the role of medium or long-term contracts is reduced because at least some projects can be built with less of the project costs hedged through long-term contracts. Projects may be built without PPAs, shorter-term PPAs, or PPAs that cover only a portion of the project's expected sales.

project financing arrangements supported by long-term PPAs remain the first choice of most power plant developers.[79]

The lower reliance on balance sheet financing in the power industry does not mean that project developers in other industries would not prefer the lower risk and financing costs that they would be able to achieve if they had long-term sales agreements. Nor does it mean that power industry developers are unable to develop projects without long-term sales agreements. Rather, the relatively low levels of balance sheet financing in the power industry appears to be an artifact of industry evolution. Specifically, the merchant generation sector has evolved based on: (1) long-term PPAs with regulated utilities (starting with mandated qualifying facility (QF) contracts in the late 1980s and early 1990s); (2) project development efforts by small companies without much equity; and (3) a reliance on highly leveraged financing arrangements.

Third, competitive retail electricity providers and companies in other capital-intensive industries, including in oil and gas, also tend to be partially (but not fully) vertically integrated to manage risks and reduce transactions costs. They have bought physical assets or signed a portfolio of contracts to manage overall supply obligations and associated risks. Partial vertical (re)integration also appears to be becoming more prevalent in electricity markets. In the United Kingdom, for example, retail suppliers have re-integrated into the generation business.[80] Similarly, generation owners are integrating vertically into retail sales, as noted in the above discussion of NRG, Constellation, and Direct Energy, and with Exelon's proposed merger with Constellation as another recent example.[81] A transition to a partially integrated industry structure has a number of potential advantages and will reduce the need for, or compensate for the lack of, extensive bilateral contracting.[82] Competition will be maintained or enhanced because the companies have a reduced ability and incentive to exercise market power and, unlike in non-restructured markets, are not *fully* integrated and do not enjoy exclusive service franchises.[83]

Consistent with these observations, we believe the deregulated electricity industry will naturally migrate to a partially vertically integrated structure that, over time, will rely less on long-term

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79 For example, the DOE reports that in 2009, 38% of all new wind generation capacity was from merchant or quasi-merchant projects that relied on short-term contracts or hedged wholesale spot market sales rather than long-term PPAs. See Wiser, *et al*. (2010), p. 34.

80 In the U.K., for example, restructuring in the early 1990s resulted in completely vertically unbundled industry structure. Today, the six largest competitive retail suppliers (supplying 99% of retail load) also own approximately 70% of the installed generating capacity. See Ofgem (2010). Note, however, that such partial integration by large companies will also tend to make it more difficult for smaller and non-integrated suppliers to enter and compete in the market. (See Ofgem, *Liquidity Proposals for the GB wholesale electricity market*, February 2010, posted at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=95&refer=Markets/WhlMkts/CompandEff

81 See Exelon and Constellation (2011).

82 For a discussion of the implications of vertical re-integration of competitive retail service and generation companies, see Meade and O'Connor (2009); Mansur (2007) "Upstream Competition and Vertical Integration in Electricity Markets," 50 J. Law & Econ. 125. http://www.dartmouth.edu/~mansur/papers/mansur_vi.pdf.

83 See, for example, Bushnell, J. B., Mansur, E. T. & Saravia, C. (2008). "Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured U.S. Electricity Markets." American Economic Review, 98, 237-266.

PPAs to underwrite new generation development. We view these trends to reflect an efficient response to deregulation, which shifts the risks of potentially uneconomic generation investments away from customers and toward developers. As increasingly large and diversified companies, these developers will be in a better position to evaluate, manage, and bear these risks. Regulatory or legislative intervention to force long-term contracting in restructured markets, even if through RPM design, carries the risk of interfering with the natural evolution of the industry with the risk of adverse long-term consequences for the efficiency of future capacity expansion.

In short, we recognize that there may be many generation projects in PJM that cannot get financed and built under current market conditions. However, while some project developers may cast this as a market failure caused by the inadequacies of RPM or state retail choice constructs, we believe the primary reason that these projects cannot get financed and built is that they are not currently needed and are currently uncompetitive with alternative sources of capacity. In the future, when these projects *are* needed for resource adequacy, we believe that market prices will rise and will make these investments attractive. However, we also recognize that it will be beneficial to both suppliers and customers if long-term contracts are enabled and not hindered by the design of RPM and state retail regulation, topics which we examine further in Section VI.F on options for extending price certainty under RPM and in Section VI.E.1 on the minimum offer price rule (MOPR).

D. Equal Compensation for Old and New Generation

A number of stakeholder comments, primarily from state commissions, relate to concerns over why old generation and demand resources receive the same compensation as new generation under RPM. This topic also relates to stakeholder comments about their disappointment that RPM has served to keep online “old and dirty” generating plants while failing to get much (if any) new generation built in eastern PJM despite prices that were higher than in the western portion of the RTO. Some of these concerns have also been raised in a recent report prepared for the American Public Power Association (“APPA”).[84]

As discussed in Section II, some new generating units have in fact been built under RPM. However, it is unclear that RPM itself induced these units to come online. Moreover, some stakeholders believe that more generation should have been built in eastern PJM where RPM prices have been higher than in the west. The main reason more generation did not enter is that it is not currently needed to maintain reliability requirements. Despite relatively higher prices in eastern PJM, these prices have been below the cost of new entry. The combination of lower peak loads, available existing generation, deferred retirements, capacity additions to existing generation, and expansion of demand response resources have made it possible to meet resource adequacy requirements at market prices below what would be needed to support the entry of more new generation.

In this section, we briefly address the environmental concerns about retaining old plants. We also discuss the differences in the time profile of capacity prices between regulated and restructure markets, and the feasibility and efficiency of differentiating capacity payments between new and existing plants.

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84 See Wittenstein and Hausman (2011).

1. Keeping "Old and Dirty" Plants Operational

State and federal legislatures and regulatory agencies set rules to reduce the environmental impacts of power generation. Recent regulations include the Regional Greenhouse Gas Initiative ("RGGI"), state renewable portfolio standards, the Maryland Healthy Air Act, and EPA regulations and related state implementation plans to meet tightening National Ambient Air Quality Standards ("NAAQS") and to reduce the output of hazardous air pollutants (HAPs).

We have not seen any evidence suggesting that existing plants are not complying with environmental regulations, even older units that have higher emission rates than new plants. Nor have we seen evidence indicating that wholesale capacity markets have contributed to greater emissions levels from these facilities. To the contrary, RPM recognizes the costs of the plants' environmental footprint in two ways. First, "dirty" plants that need to install control technology to comply with environmental regulations will include the costs of such investments in their capacity market offers. For example, in the 2014/15 auction, many resources needing environmental retrofits either opted not to offer or offered at higher levels, and not all cleared when other resources could provide capacity more cheaply, as discussed in Section II. Uncleared plants may consequently retire and the cleared resources will install pollution controls. Second, higher emissions rates result in higher allowance costs, which reduces the dispatch frequency and the energy margins these plants earn. This will reduce their emissions and tend to raise their capacity market offers (and the IMM's offer caps), which will make them more likely not to clear in RPM in the future. Thus, RPM internalizes both the variable and fixed costs of complying with existing and planned environmental regulations. With these costs internalized, the competitive wholesale markets facilitate compliance with environmental regulations at lower costs while still maintaining resource adequacy.

If there are any concerns over the remaining environmental footprint of existing generation assets, they should be addressed through stricter federal and state environmental standards. Otherwise, RPM cannot be expected to implement environmental standards that do not exist. Nor should RPM be expected to impose indirectly tighter environmental standards than state and the federal governments have deemed appropriate. In our opinion, RPM is performing well in terms of incorporating the costs of existing and planned environmental regulations. The adequacy of the environmental regulations themselves should not be a factor in the assessment of whether RPM is achieving its objectives.

2. The Time Profile of Capacity Prices in Restructured vs. Regulated Markets

The position that older plants should not be compensated for capacity at the same level as new plants is often related to a misunderstood or under-appreciated difference in the time profiles of capacity prices in regulated and fully-restructured power markets. While it is generally understood, for example, that the price a tomato farmer receives for his tomatoes does not depend on the age of his tractor, this paradigm does not apply in cost-of-service regulated industry. Under cost-of-service regulation, the price charged for a power plant is determined by its accounting costs. As a result, new plants will generally be more expensive than old plants, at least until major capital additions are needed at the old plant. This declining revenue profile for power plants in a cost-of service regulated environment does not exist in restructured markets. In restructured markets, even the administratively-determined cost of new entry is calculated as the "levelized" cost of a new plant, which creates a revenue path that is either constant over time (if costs are levelized in nominal dollar terms) or increasing over time (if costs are levelized in real dollar terms). Long-term PPAs signed through competitive procurement similarly often have pricing paths that are either constant or increasing over time. This time profile of cost recovery means older plants are paid the same for the capacity they provide as new plants. The time profile differs substantially from the time profile under cost-of-service regulation, under which the cost of new plant exceeds their "levelized costs" during the early part of the plants' life but is lower during the latter years.

Moreover, in a cost-of-service regulated environment, retail rates will reflect the cost of generating capacity only after new generating resources are placed in service and reflected in utilities' rate bases. This means there can be a lag of several years before regulated retail rates reflect the addition of expensive new capacity resources. This lag causes a significant misalignment of retail prices and investment signals. Because demand continues to grow due to low rates, more new resources may be added to the system than will ultimately be needed when retail prices increase to reflect the added costs. This can lead to excess capacity, high regulated retail rates, and the risk of stranded costs or regulatory disallowances.

The time profile of capacity prices is quite different in restructured power markets. As in all other competitive markets, the market price for capacity will increase before new generating capacity needs to be added. As market participants perceive an approaching scarcity of generating capacity, market prices for capacity will increase and, in response, market participants will identify the lowest-cost resources that can operate profitably at the anticipated market prices. In order to invest in new generation, competitive suppliers must expect to receive high enough capacity prices over the plant's entire economic life (including later years when the plant is aging). If capacity prices are reflected in retail rates or are otherwise made available to demand-side resources, this market-determined portfolio of resources will also include demand-response resources. The fact that capacity prices increase before new resources are actually added to the system will dampen demand growth and reduce the resource need and long-term costs.

The fact that prices in eastern PJM have increased even before much new capacity has been added, has led some stakeholders to question the value and effectiveness of capacity market and restructuring in general. However, we believe the observed price path is consistent with market fundamentals and efficient market outcomes and will result in lower costs over the long term.

3. Differentiating Capacity Payments for New and Existing Resources

The very design of capacity markets or capacity payment mechanisms raises the question of whether all resources should receive capacity payments, or whether such payments should be limited to new resources and resources which would otherwise retire. Limiting capacity payments to new resources is appealing to some because at first glance it appears that it would reduce the total costs associated with such capacity payments. Arguments of this sort are deceptively attractive, but they fail to consider the long-term impacts that would undermine efficient market signals and ultimately increase system costs.

If a resource adequacy requirement is to be met through a market mechanism, whether a centralized capacity market or solely by relying on bilateral contracts, the capacity from all resources that can be used to satisfy the requirement will have the same capacity value. As a result, capacity revenues available to existing and new resources cannot be differentiated in such a market environment. Even if RTO-administered capacity markets were limited only to new resources, the full market value of capacity would still be captured by all existing resources through bilateral contracts, assuming that the resources are not cost-of-service regulated or under existing fixed-priced contract.

When limiting capacity payments to new resources or existing resources that would otherwise retire, it is also necessary to recognize that a sizeable portion of the existing pool of resources would be forced to retire in the absence of capacity revenues. For example, we have shown in our 2008 RPM Report that in the six years before RPM was introduced in PJM, between 500 MW and 3,500 MW of generating resources retired each year.[85] After RPM was introduced, annual retirement dropped to a range of zero to 500 MW for the first five BRAs. More importantly, however, an analysis of market monitoring data showed that at least 30,000 MW of PJM's capacity resources were at risk for retirement in the absence of capacity payments due to revenue deficiencies in PJM's energy and ancillary services markets. This is not surprising considering that the going-forward costs of many existing resources can be high even in comparison to new resources. As a result, capacity auctions will generally select new capacity resources even when cost-based bids for many of the existing resources do not clear. For example, in PJM's auction for the 2011-12 planning year, a total of 2,337 MW of new capacity cleared in the auction, while 496 MW of new capacity did not clear.[86] In comparison, 4,600 MW of capacity from existing resources did not clear, even though the bid prices for the existing resources were mitigated to reflect their incremental costs. These data show that the all-in costs of retaining existing plants can even exceed the costs of new plants. This is because existing plants are sometimes more expensive, and keeping them operational may require significant ongoing costs (*e.g.*, high annual repair, refurbishment, and maintenance costs) as well as occasional substantial investments (*e.g.*, environmental retrofits or replacements of major plant components).

Only in power markets that do not impose resource adequacy requirements on LSEs can capacity payments be targeted specifically to new resources or the retention of existing resources. However, such a differentiation of payments between old and new generation would cause significant market distortions that, while potentially saving costs in the short-term, would result in substantial inefficiencies and higher costs in the long term.[87] Subsidizing the entry of new plants through above-market long-term contracts results in similar distortions and long-term costs. While these out-of-market mechanisms will suppress market prices in the short term, the market distortions they create will perpetuate and accelerate the need to expand the scope of such subsidies or other out-of-market solutions to maintain reliability. Again, this solution will likely be less efficient and more costly in the long-term.

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85 Pfeifenberger and Newell, *et al.* (2008), p. 20.

86 Pfeifenberger and Newell, *et al.* (2008), p. 36.

87 For a case study of the adverse consequences of imposing different prices for "new" and "old" resources, refer to the discussion of inefficiencies, reduced investment incentives, and overall welfare losses resulting from the different regulation of prices for "old" and "new" natural gas prior to the implementation of the Natural Gas Policy Act of 1978 as discussed in Viscusi, Vernon, and Harrinton (2000), pp. 616-632.

E. RPM'S ABILITY TO REPLACE OR PREVENT HIGH ENVIRONMENTAL RETIREMENTS

Several stakeholders expressed concern about RPM's ability to replace or prevent excessive simultaneous retirements caused by EPA's new HAP MACT and other regulations. Indeed, the slew of regulations currently being promulgated is likely to impose major stresses on electricity markets and the supply chain for environmental control equipment. These challenges are being felt nationally and are not limited to PJM. The reason for particular concern about RPM is that it is a restructured market which, unlike traditionally regulated systems, lacks centralized resource planning. RPM includes "buy bids" for capacity (up to their price cap for existing capacity), but there is no guarantee that enough capacity will retained below that price cap or offered from new resources to replace potentially large amounts of retirements.

1. RPM Facilitates Retrofits and Procures New Capacity Economically

RPM is designed to procure enough capacity to meet resource adequacy targets and to do so in an economically efficient, market-based fashion. RPM facilitates retrofits by allowing offers from existing generation to include the cost of retrofits. If the offer clears, the resource will earn at least its offer price with the prospect of recovering its retrofit costs. Existing resources will not clear only if lower cost resources are available to replace it (or the price cap is hit, which is unlikely). If the resource is not offered at all, replacement capacity can be procured. RPM supports new entry through its 3-year forward period, which provides enough lead time for a variety of new resources to enter, including new demand-side resources, generation uprates, and new generation.[88] Furthermore, RPM's centralized clearing and pricing transparency facilitate efficient economic tradeoffs between all such resource options. RPM also includes three incremental auctions after each base auction, each of which provides opportunities to procure addition capacity.

So far, these provisions have worked as intended. RPM has successfully and economically supported resource adequacy, including when the Maryland Healthy Air Act was implemented in 2009/11 and under the challenging conditions presented by EPA's HAP MACT regulations partially reflected in the most recent BRA for the 2014/15 delivery year. In that auction, 3.2 ICAP GW of existing generation was excused from offering, up from 1.2 GW the prior year (with FRR excused and other excused resources likely withdrawn for environmental reasons); 10.6 ICAP GW cleared at higher prices above \$50/MW-day (4.4 GW above \$100/MW-day), reflecting the costs of scrubbers and other environmental retrofits; and 10.2 ICAP GW (including all new PJM members such as ATSI) of existing generation was offered but did not clear. Despite these reductions of capacity from existing generation, and sufficient replacement capacity was procured, largely in the form of demand side resources. Furthermore, there were new resource offers that did not clear but could have if they had been needed and prices had been higher. (See Section II).

2. The Future is Uncertain and Retirements Should be Monitored

So far, RPM has performed successfully under the challenges presented by EPA's HAP MACT regulation through the 2014/15 delivery year. However, RPM has not been tested with larger

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[88] As discussed in Section III.C, concerns that RPM does not support new generation are largely unfounded.

amounts of simultaneous retirements within the LDAs. It is too early to tell how well RPM (or any other construct) will mitigate the retirement threats caused by the full slate of tighter new regulations planned to take effect between 2015 and 2018.

Additional emerging regulations on *air quality* to be effective during that period include likely tighter emission limits and regional/state caps on NOx and SO_2 due to EPA's expected revisions to air quality standards for ozone, particulate matters ($PM_{2.5}$), and SO_2. These air quality regulations will affect all fossil fuel generation plants, but especially coal- and oil-fired plants. Furthermore, EPA proposed regulations on *cooling water* intake structures at generation plants to reduce damage to aquatic organisms due to impingement and entrainment. Under the proposed rule, states will determine what specific controls (such as mesh screens or cooling towers) would be required to be installed at each covered generation facility (including nuclear, coal, gas and oil plants). EPA has also proposed regulations on handling and disposal of *combustion by-products* (such as ash) which may require additional equipment on coal plants and may essentially eliminate surface disposal of wet coal ash. Finally, EPA is expected to issue proposed rules this year for *greenhouse gas* ("GHG") performance standards applicable to new and modified generation plants. The impact of this new NSR rule on existing power plants will in part depend on EPA's interpretation of major modifications (*e.g.*, whether repairs are considered major modifications), which has been a central issue in numerous litigation cases between EPA and plant owners with respect to criteria pollutants. The combined and fairly simultaneous impacts of these emerging EPA regulations on air quality, cooling water, combustion by-products, and GHG will likely contribute to early retirements of a significant portion of the existing generation units over the next five years. Future CO_2 prices under a potential federal climate policy would additionally increase the retirement pressures on coal-fired plants.

Hence, despite RPM's design and success to date, it is not possible to predict exactly what will happen if a large number of plants retired simultaneously. Such simultaneous retirements would be a challenge in any system and could lead to difficult-to-manage spikes in retrofit costs. Given these risks, PJM will undoubtedly continue to monitor closely potential retirements through communications with generators and its own analysis.[89] Vulnerabilities identified could be used to ensure that the appropriate LDAs are being modeled and to check that sufficient new resources are being pre-qualified for the auctions. If not, both PJM and the states will need to pursue options to entice existing capacity to stay online or to procure new resources.

Another risk that PJM will need to monitor is the possibility that environmental regulations which force a large number of retrofits during a single year could produce spikes in RPM prices for a single auction, followed by price decreases in the next auctions to levels too low to allow for cost recovery of the retrofit investments. If that occurs, the offer cap provisions for environmental retrofits may have to be revisited. A number of the recommendations we present in the remainder of this report, such as more proactive modeling of LDAs, would provide additional safeguards to ensure RPM can address these challenges.

F. The Dependability of Demand Resources

PJM stakeholders, primarily generators, voiced a range of concerns regarding the dependability of demand-side resources. These stakeholders are concerned that DR development plans may

[89] See PJM (2011p); see also PJM (2011z) and ERCOT, MISO, NYISO, PJM and SPP (2011).

not be fulfilled if the market becomes saturated, that DR does not face the same obligations as does generation, that there is no historical record indicating how DR will perform as required at high penetration levels, and that these problems may become more acute as DR penetration rises and starts displacing larger amounts of generation.

1. Market Saturation Concerns about Planned DR

In the 2014/15 BRA, demand-side resources (DR and EE) accounted for 14.9 GW of capacity (UCAP), or 9.4% of total resources committed. This is 4.0 GW more than the demand-side capacity (DR and ILR) committed for the current 2011/12 delivery year. While the amount of DR capacity cleared for 2014/15 is impressive, we see no evidence that its performance should be considered speculative. First, to our knowledge demand-side resources committed for the current delivery year have been performing well during the recent heat waves. Second, while the 4.0 GW increase over the next three years compared to the current delivery year is ambitious, it is smaller than the 6.0 GW increase that occurred over the past three years. Third, demand resources are exposed to verification and penalty provisions for resource deficiencies and performance violations that are roughly similar to those of generation resources and should be sufficient to ensure performance. Finally, DR resources have exchanged their BRA commitments in incremental auctions at a rate no higher than generation resources and future incremental auctions will still be available as safeguards that would allow replacements of commitments that could not be fulfilled.

On the other hand, there is at least some indication that some providers may have overestimated their ability to enroll a sufficient number of customers to fulfill their DR capacity commitments in some areas. For example, one curtailment service provider ("CSP") filed a motion with the Public Service Commission of Maryland to amend its demand response capacity agreements with three utilities, after it encountered a number of problems attempting to contract with new customers to provide DR capacity required under those agreements for the 2011/2012 delivery year. The company cited "substantial competition from other providers also offering demand response services" as one of three reasons.[90]

To incentivize CSPs to offer only realistic amounts of "planned" DR and to develop them, RPM imposes deficiency penalties for failure to produce the resources or procure replacement capacity. As a possible additional safeguard to identify deficiencies early, PJM should consider monitoring development plans more closely, as discussed in Section VII.

2. RPM Design Issues for Accommodating Large Amounts of DR

The primary concern with relying on large amounts of DR (as a substitute for new generation resources) is that the frequency of potential calls increases as DR penetration rises. If DR resources are seasonally limited or contractually obligated to respond to dispatch instructions only a certain number of times, reliability could be compromised at higher levels of DR penetration. PJM has already addressed this concern by restricting the total amount of "Limited Summer" DR resources, introducing new DR products, and imposing minimum requirements for "Annual" and "Extended Summer" DR resources. We find this DR-related extension of RPM auction design to be a reasonable solution to the problem. Based on our

[90] Megawatt Daily, "Enernoc seeks amendments to Md. Contracts," June 30, 2011.

analysis presented in Section II of this report, we also find that this approach is working as intended.

Furthermore, if resources are found to underperform relative to their obligations in the future, they will face penalties similar to those imposed on generators. However, because large amounts of Annual DR is unlikely to be called very frequently under normal system conditions, it might be possible for a CSP to offer some limited resources as Annual resources without a high risk of being called upon and penalized if the resource cannot perform. To provide additional safeguards against such under-performance concerns, we recommend that PJM consider strengthening its verification processes by reviewing just prior to each delivery year whether DR resources would likely be able to respond as claimed. Such a review could include verifying the seasonal or annual nature of the load to be curtailed and whether there are any contractual limitations to the number of calls. These recommendations are discussed further in the context of comparability of DR and generation resources in Section VI.C of this report.

G. RPM Target Procurement

Stakeholders representing load and some of the state commissions raised concerns over the accuracy, economic efficiency, and transparency of reliability targets and load forecasts. A number of these concerns have also been raised publicly.[91] As stakeholders recognize, PJM's reliability targets and load forecasts determine the amount of capacity procured under RPM, both on an RTO-wide and LDA level. There are major implications for total annual capacity payments imposed on PJM load serving entities and capacity payments provided to generators. Under RPM, these payments can range from $5 billion to $15 billion annually and can vary significantly from one year to the next and from one LDA to the other based on market conditions, updates to LDA-internal resource adequacy requirements, and forecasts of future peak loads.

The RPM target procurement of capacity is a function of (1) the forecast of weather-normalized peak load for the RPM delivery year, and (2) the reliability requirement, which determines target reserve margins. At the RTO-wide level, PJM resource adequacy planning is based on a reliability requirement defined as the 1-day-in-10 years Loss of Load Expectation ("LOLE"). Within individual LDAs, the reliability requirement is determined based on a "conditional" LOLE target of 1-day-in-25 years, as explained below.

The purpose of RPM is to procure sufficient capacity so these reliability standards are satisfied on an RTO-wide and LDA-specific basis. As such, the scope of our RPM performance review

[91] For example, see Public Power Association of New Jersey, March 8, 2010 and December 2, 2010 letters to John Reynolds and Steven Herling re "Request for Consultant Review of PJM's Load Forecasting Methodology" from a group of residential, commercial and industrial consumers, state regulators and consumer protection agencies, and load-serving entities on the PJM system; Comments submitted on behalf of the Public Utilities Commission of Ohio in FERC Docket No. RM10-10, "Proposed Reliability Standard, BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 27, 2011; J.F. Wilson, "Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?," Public Utilities Fortnightly, April 2010 and "Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid," Public Utilities Fortnightly, May 2010; and J.F. Wilson, "Review of CETO Methodology: LDA LOLE Criterion ('One Day in 25 Years'), presentation to RAAS, April 7, 2011.

includes an evaluation of how well RPM is meeting that goal, not the reliability target that RPM is designed to achieve. However, given the concerns articulated by stakeholders, we recommend that PJM consider re-examining the economic efficiency and cost-effectiveness of RPM reliability targets, in particular the methodology to determine LDA-specific reliability targets.

We also recommend that PJM increase the transparency and stakeholder understanding of the load forecasting process. However, we address load forecasting separately, in Section VI.B of our report, since increasing the transparency of the load forecasting process and increasing market participants' understanding of load forecasting uncertainties would also increase RPM price transparency and reduce RPM-related risks associated with load forecasts as one of the main administratively-determined RPM parameters.

1. The Use of RTO-wide Reliability Targets to Define the VRR Curve

On an RTO-wide basis, the VRR curve is anchored at the target reserve margin plus one%. The target reserve margin is based on a reliability target defined as a 1 day in 10 years Loss of Load Expectation (LOLE). The reasonableness of the 1 day in 10 year standard was reaffirmed by FERC earlier this year.[92] However, the FERC order also emphasized that "the one day in ten years criterion is one common approach for resource adequacy assessment, and by approving this regional Reliability Standard, the Commission does not establish the one day in ten years criterion to be the de facto, or the only acceptable metric for resource adequacy assessment."[93] The Commission further noted that it did "not disagree with commenters' arguments that the one day in ten years criterion could be improved."[94] Some PJM stakeholders also suggested that the standard should be improved, particularly because the economic rationale for the current standard has not been widely discussed. Moreover, stakeholders' doubts about the reliability standard itself seem to undermine their confidence in the efficiency and cost effectiveness of RPM.

As we already noted in our 2008 RPM Report, cost-effective reliability targets will not be entirely independent of the cost of capacity. As the cost of capacity increases, customers presumably would be willing to accept a slightly lower level of reliability. In other words, the economically-efficient demand for reserve capacity will tend to decrease as the cost of that capacity increases—a relationship which can be expressed by a sloped demand curve for reserve capacity. This demand curve for reliability would procure, at least theoretically, an optimal reserve margin that decreases as the cost of adding capacity increases.

To assess this "demand" for reserve capacity and derive an economically-efficient reserve margin target would require a detailed assessment of the value of incremental planning reserves. Others have suggested that the value of additional reserves is equal to the customers' Value of Lost Load ("VOLL"), such that an optimal reserve margin could simply be derived by estimating VOLL, the degree to which additional capacity reduces the expected amount of customer curtailments (*i.e.*, the Expected Unserved Energy or "EUE"), and the cost of additional

[92] FERC Order No. 747, Planning Resource Adequacy Assessment Reliability Standard, 134 FERC ¶ 61,212 (issued March 17, 2011).

[93] *Id.* at ¶31.

[94] *Id.* at ¶32.

capacity.[95] However, this is not quite the case. The value of increasing planning reserve margin also includes a number of economic benefits in addition to reducing the amount of curtailed load.[96] As was seen during the California energy crisis, the primary economic consequence of reliability-related events is not necessarily the frequency or duration of firm load shed events, but excessively high power costs. Thus, the economic value of increased reserve margins also includes the high cost of emergency supplies procured or dispatched to avoid customer load curtailments as well as the insurance value of reducing the likelihood of extremely high-cost outcomes. For example, adding a combustion turbine to the system not only reduces the risk of curtailing load during emergency conditions, it also reduces production costs by allowing the dispatch of the turbine whenever the dispatch or opportunity cost of dispatching alternative resources would exceed the dispatch cost of the turbine—including high-cost imports, DR capacity with high dispatch costs, generation dispatched within their emergency limits, or energy-limited resources with high opportunity costs. In fact, these benefits of additional resources can be more important to the determination of economically efficient reserve margins than the value of VOLL, which is difficult to measure and ranges widely across customer types.

Unfortunately, these additional energy cost and risk mitigation benefits of higher reserve margins are also not yet widely understood. Moreover, an explicit analysis of the tradeoff between the marginal benefits and marginal costs of additional capacity is not routinely performed to determine reliability requirements.[97] We have recommended in our 2008 RPM Report that PJM and stakeholders examine the tradeoffs between reliability targets and the cost of new capacity as part of a broader re-evaluation of the level and application of current reliability criteria. While outside the scope of our RPM review, we believe such a study would still be helpful because it would (1) examine the tradeoff between the costs of incremental capacity and the benefits of that capacity including reliability, reduced energy costs, and reduced emergency purchases; (2) inform stakeholders about the value customers are receiving in exchange for paying for reserve capacity; (3) compare the 1-in-10 reliability standard to an economically efficient target; and (4) help determine the natural slope of the demand curve based on a cost-effective tradeoff between target reserve margins and the expected level of and uncertainty of in total reliability-related costs.

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95 For example, see J.F. Wilson, "Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?," Public Utilities Fortnightly, April 2010 and "Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid," Public Utilities Fortnightly, May 2010; R. Borlick, Comments in FERC Docket No. RM10-10, "Proposed Reliability Standard, BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation," December 27, 2011.

96 Carden, Pfeifenberger and Wintermantel, "The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On," National Regulatory Research Institute Report 11-09, April 2011.

97 We are aware of only a few examples of recent analyses to determine economically efficient reserve margins, including studies by Southern Company, the Tennessee Valley Authority, and Louisville Gas & Electric.

2. The 1-in-25 Standard for Setting LDA-Level Reliability Targets

Stakeholders have raised concerns specifically about the reasonableness of the reliability standard that is applied to individual LDAs.[98] The LDA-level reliability requirement based on the 1-day-in-25 years standard also is a major determinant of RPM auction outcomes within LDAs and—in interaction with other administrative parameters such as CETL, transmission planning decisions, and load forecasts—a significant factor contributing to administrative uncertainty of LDA capacity prices.

As we explained in our 2008 RPM Report, reliability targets within individual LDAs, which define LDAs' transmission import objectives (CETO), are set based on an LOLE of 1 day in 25 years. This is a *conditional* LOLE, because the LDA's imports are treated as if they were 100% available, in spite of the fact that neither the transmission capability into the LDA nor PJM generation outside the LDA is guaranteed to be 100% available in actual operations. The *unconditional* LOLE for the PJM footprint is 1 day in 10 years, which includes the possibility that generation supply is inadequate (but assuming unlimited transmission within the PJM footprint). This means that within an LDA the combined LOLE target is approximately the sum of (1) one day in ten years; plus (2) one day in 25 years; plus (3) the LOLE associated with transmission line outages or derates.[99] This means that within transmission constrained LDAs, the total LOLE is at least 1.4 days in ten years,[100] depending on the transmission dependence of the LDA.

We recommended in our 2008 RPM Report that PJM evaluate whether the 1-in-25 year conditional LOLE target, which is invariant with the transmission dependency of individual LDAs, is reasonably optimal. We understand that PJM is already in the process of reviewing the 1-in-25 standard with its stakeholders and recommend continuation of this effort.

It is likely that a more refined determination of LDAs' LOLE targets would result in targets that vary with the degree of each LDA's import dependence. Presumably, an LDA that is highly reliant on imports would have a more stringent target (recognizing that the assumption that imports are 100% available is particularly optimistic) than an LDA that is less dependent on imports. A more refined determination of LDAs' reliability requirements may be achievable by studying PJM-wide resource adequacy through multi-area reliability simulations that consider the reliability of transmission import capabilities and simultaneously determine both footprint-wide and LDA specific LOLE levels. Such multi-area reliability modeling could also be combined with economic reliability simulations that would assess the economic tradeoffs between the cost and value of additional reliability.

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98 J.F. Wilson, "Review of CETO Methodology: LDA LOLE Criterion ('One Day in 25 Years')", presentation to RAAS, April 7, 2011.

99 See PJM (2011x), Section 4.

100 $1/10 + 1/25 = 0.14$ days per year = 1.4 days in 10 years.

IV. ANALYSIS OF NET COST OF NEW ENTRY

In this section of our report we analyze the Net Cost of New Entry (Net CONE) as used in RPM. We first present the results of our concurrent study updating engineering-based estimates for the gross cost of new entry (CONE) for the 2015/16 delivery year. Detailed documentation of these CONE estimates is provided in our separate report and associated data files. We present here the summary of our recommended CONE estimates for simple-cycle and combined-cycle plants for each of the five PJM CONE Areas.

We provide these CONE estimates for consideration by PJM and stakeholders according to the PJM Tariff, which requires that CONE be fully reevaluated every three years while the other years are updated by trending the previous CONE estimate based on the Handy-Whitman index.[101] The new CONE estimates, if adopted, would be used as a key parameter defining the VRR curve and as inputs to mitigation thresholds under the Minimum Offer Price Rule (MOPR).

Section IV.B analyzes the energy and ancillary services (E&AS) offset used in determining Net CONE. We examine the accuracy of the administratively-determined historical E&AS offset compared to the E&AS margins actually earned by generating units similar to the reference technology. We also evaluate two potential changes to the E&AS methodology, including: (1) whether the E&AS offset should be a backward-looking, forward-looking, or equilibrium estimate; and (2) whether the new scarcity pricing mechanisms, when implemented, would warrant any adjustments to the E&AS approach including possible true-up mechanisms.

Finally, this section of our report briefly examines the prices at which new generating units have offered into RPM to evaluate the feasibility of determining Net CONE empirically based on these offer data.

A. GROSS COST OF NEW ENTRY

Updated CONE estimates are needed once every three years for PJM and stakeholder review. These estimates, if adopted, would be used for two purposes: (1) to calculate Net CONE (in conjunction with the administratively-determined E&AS offset) to define the price points of the VRR curve; and (2) as the basis for calculations to screen for and mitigate capacity offers from new generators that may be uncompetitively low according to the MOPR, as discussed further in Section VI.E. The detailed engineering cost study summarized here is presented in our separate report, *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM* (CONE Report).

After summarizing the results of our CONE Report, we explain our recommendation to continue using a combustion turbine (CT) as the marginal resource type to be used as the reference technology for estimating Net CONE. We also examine the implications of using a "level-nominal" versus a "level-real" cost annualization method for determining CONE. We recommend that PJM and stakeholders consider transitioning to a level-real approach to reflect projected escalation in future CONE values and associated market prices due to continued

[101] See PJM (2011q), pp. 2278-2280.

escalation of the capital cost of new plant. This recommendation, however, is contingent upon combining it with our recommendations to calibrate the E&AS offset (Section IV.B) and increase the cap of the VRR curve to address identified RPM performance concerns (Section V).

1. Levelized Cost Estimates of a New Simple-Cycle and Combined-Cycle Plant

As discussed in the CONE Report, our effort to estimate the levelized costs of new entry includes:

- A screening and siting study to determine the appropriate technology type and county to use as the basis for our cost estimate in each CONE Area;
- Details on the reference plant performance and technical specifications;
- An engineering cost estimate by CH2M HILL of the plant-proper engineering, procurement, and construction (EPC) costs and major equipment costs;
- Owner's costs incurred during project development, construction, and operations;
- An estimate by Wood Group of the ongoing fixed operations and maintenance ("FOM") costs that would be incurred by such a plant; and
- A study of the appropriate cost of capital for a merchant developer in PJM, for use in annualizing plant capital costs.

Here we simply summarize (1) the selected plant specifications that were used as the basis for developing our estimates and (2) the resulting capital costs of that study in comparison with the most recent previous CONE studies.

Table 14 and Table 15 contain the summary siting and plant specifications used as the basis for the CT and CC CONE estimates in each CONE Area. To determine the site locations shown in Table 14 we first selected locations with access to high voltage transmission infrastructure and at least one major gas pipeline. Among counties with sufficient infrastructure, we identified both the locations with the highest number of gas CCs and CTs recently built or under construction, and whether industrial land is currently available in those locations. Site selection for the SWMAAC CONE Area proved more difficult due to both a lack of recent new entrants (or units under construction) and a lack of vacant industrial land in many parts of Maryland. For SWMAAC we selected Charles County, Maryland based on: (1) gas and electric infrastructure availability; (2) the availability of vacant industrial land as indicated by property listings; and (3) Charles County is the location of the only permitted large gas facility proposed in SWMAAC, which is the 640 MW CPV St. Charles project.[102]

[102] Data on recent gas CC and CT builds based on Ventyx (2011).

Table 14
Site Specifications for CONE Estimates by CONE Area

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

Source: CONE Report, pp. 8.

The reference plants' technical specifications are summarized in Table 15. CH2M HILL used these plant specifications as the basis for engineering estimates of plant construction costs. These specifications were chosen to most closely reflect the types of projects that have been built recently or are currently under construction. Design details, such as the type of environmental controls and dual-fuel capability, were based on both an analysis of recent plant additions and an assessment of environmental compliance requirements.

The chosen simple-cycle reference technology is a plant with 2 GE 7FA.05 turbines, fitted with selective catalytic reduction (SCR) in all CONE areas other than Dominion. The net summer capability of these CT plants is 390 MW (392 MW without an SCR). The combined-cycle reference technology is a 2×1 plant using GE 7FA.05 turbines, fitted with an SCR. The net summer capability of these CC plants is 584 MW at baseload or a maximum 656 MW when duct firing. For both the CC and CT, all facilities are equipped with dual-fuel capability in all locations except CONE Area 3 representing the unconstrained RTO (*i.e.*, western portions of PJM). We also provide estimates for adding dual-fuel capability in CONE Area 3 and adding SCRs in the Dominion CONE Area.

The installed and annualized cost estimates for these reference CT and CC plants are presented in Table 16 and Table 17 in 2015 dollars. These tables also compare our results with the most recent PJM CONE studies conducted by Power Project Management, LLC in 2008, inflation adjusted to 2015 dollars. The overnight capital cost estimates in these tables include all EPC contractor costs, major equipment costs, and other owner's costs incurred during project development and construction. The majority of these capital costs were estimated by CH2M HILL using the same cost estimation methods that they apply when bidding on projects as an EPC contractor. We independently developed a subset of owner's capital costs that are not included in the CH2M HILL estimates, including electric and gas interconnection costs based on costs actually incurred by recent projects. Estimates of ongoing fixed O&M costs are based on O&M fee estimates from Wood Group and our own estimates of other owner's costs, such as plant insurance and property taxes.

Table 15
Plant Technical Specifications for the Reference CC and CT

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

Sources: CONE Report, pp. 18.

Estimating the annual revenues required to cover the investment and other fixed costs of a new plant requires translating the plant's investment costs into annualized costs. In a regulated cost-of-service environment, this stream of annualized costs is based on accounting costs, including depreciation expenses, debt service expenses, taxes, and the allowed return on equity. In restructured, competitive markets, annualized costs are often based on what is referred to as "levelized" costs. Levelized costs are calculated such that receiving net revenues equal to these levelized costs over the cost-recovery period (here 20 years) provides sufficient funds to recover the investment, a return on the investment, taxes, and other fixed costs. Such levelized costs are often the basis for the contract price in long-term power purchase agreements, which may be structured as annual payments that are constant over the contract duration or as annual payments that increase over time. Such contract escalation rates are often tied to the expected inflation rate.

A calculation of levelized capital costs requires an estimate of generation developer's financing costs. We recommend financing parameters consistent with the costs of a merchant generator using balance sheet financing without a long-term power purchase agreement (PPA). To the extent generation projects would be developed with long-term contracts, this would reduce overall financing costs because investment-related risks would be transferred to the contract counterparty. As discussed in Section III.C, the lower risk with a PPA reduces financing costs because it allows for financing with a higher proportion of debt and reduces the costs of project-related debt and equity. However, the financing costs of such a highly-leveraged project would be inappropriate as a benchmark for determining the cost of new entry. We believe CONE estimates should represent the costs of a merchant plant exposed to the revenue uncertainty in PJM's capacity market.

As documented in our CONE Report, we estimate these financing costs of a merchant plant to be equal to an 8.5% after-tax weighted average cost of capital. This is equivalent to 50 percent debt and equity financing at a 12.5% cost of equity, a 7.5% cost of debt, and an approximately 40% combined federal and state tax rate.[103] As shown in our CONE Report, this cost of capital estimate is derived for a sample of publicly-traded merchant generation companies and is consistent with financing cost data from a number of independent sources, including fairness opinions prepared by investment banks in the context of recent mergers and acquisitions. In addition to these cost of capital estimates and discussed further in our CONE Report, levelized cost estimates are based on a cost recovery period of 20 years, Modified Accelerated Cost Recovery System ("MACRS") schedules consistent with industry practice and the previous PJM CONE studies,[104] and our estimate of a 2.5% long-term inflation rate.

Table 16
Installed and Levelized Cost Estimates for 2015/16: Reference Combustion Turbine

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CT CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$308.3	390	$791.2	$15.7	8.47%	$112.0	$134.0	$142.1
2 Southwest MAAC	$281.5	390	$722.6	$15.8	8.49%	$103.4	$123.7	$131.4
3 Rest of RTO	$287.3	390	$737.3	$15.2	8.46%	$103.1	$123.5	$135.0
4 Western MAAC	$299.3	390	$768.2	$15.1	8.44%	$108.6	$130.1	$131.4
5 Dominion	$254.7	392	$649.8	$14.7	8.54%	$92.8	$111.0	$131.5
Power Project Management, LLC 2008 Update								
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)								
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%	n/a	$154.4	n/a
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%	n/a	$142.8	n/a
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%	n/a	$146.1	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Dominion estimate excludes an SCR; with SCR CONE increases to $100.8/kW-year level real and $120.6/kW-year level nominal.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $110.7/kW-year level real and $132.5/kW-year level nominal.

PPM's estimates from Power Project Management (2008).

PPM's numbers are escalated according to historical inflation over 2008-2011 and at 2.5% inflation rate over 2011-2015, see CONE Report Section VI.A.

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[103] We use slightly different cost of capital rates in different states consistent with the state income tax rate in each location.

[104] See, for example, Power Project Management (2008) and Pasteris (2011).

Table 17
Recommended Gas CC CONE for 2015/16

CONE Area	Total Plant Capital Cost ($M)	Net Summer ICAP (MW)	Overnight Cost ($/kW)	Fixed O&M ($/kW-y)	After-Tax WACC (%)	Levelized Gross CONE Level Real ($/kW-y)	Levelized Gross CONE Level Nominal ($/kW-y)	PJM 2014/15 CC CONE ($/kW-y)
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$621.4	656	$947.8	$16.7	8.47%	$140.5	$168.2	$179.6
2 Southwest MAAC	$537.4	656	$819.6	$16.6	8.49%	$123.3	$147.6	$158.7
3 Rest of RTO	$599.0	656	$913.7	$16.0	8.46%	$135.5	$162.2	$168.5
4 Western MAAC	$597.4	656	$911.2	$15.8	8.44%	$135.2	$161.8	$158.7
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8	$158.7
Pasteris 2011 Update								
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)								
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%	n/a	$179.6	n/a
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%	n/a	$158.7	n/a
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%	n/a	$168.5	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $138.9/kW-year level real and $136.3/kW-year level nominal.

Pasteris Energy's 2011 CONE estimates were used as the basis for the CC CONE estimate for the 2014/15 delivery year, see Pasteris Energy (2011), pg. 55.

Pasteris Energy's numbers are escalated at 2.5% inflation rate, see CONE Report Section VI.A.

Table 16 and Table 17 report two sets of levelized cost estimates, one based on "level-nominal" and the other based on "level-real" cost recovery. The level-nominal cost recovery reflects levelized payments that are constant over time in nominal dollar terms, which means they do not increase over time with factors such as inflation. In contrast, level-real cost recovery reflects levelized payments that are constant in inflation-adjusted real terms, which means they are assumed to increase with our estimated long-term average inflation rate of 2.5%.

PJM's calculation of CONE is currently based on the level-nominal approach, although level-real costs were used for the purpose of the MOPR until recent changes to MOPR switched to the level-nominal approach to annualize costs. As we explain in more detail below, we believe setting CONE equal to level-nominal costs will overstate annualized costs over time and, as a result, could lead to over-procurement under RPM—assuming administratively-determined E&AS offset are accurate.

2. Selection of Resource Type to be Used as the Reference Technology

We recommend maintaining a CT as the reference technology for the determination of Net CONE for purpose of defining the VRR curve based on several considerations. First, RPM is designed to achieve capacity prices approximately equal to prices one would expect in a long-run market equilibrium. Over time, multiple resource types will be needed including baseload, intermediate, and peaking units. In a market equilibrium, all of these resources will have the same Net CONE. As a result, the choice of reference resource type would not matter as long as the resource type is among those that are economically viable and Net CONE is accurately calculated.

Second, Net CONE for each resource depends on both Gross CONE and the E&AS margin the generating units can expect to earn. Of these two components, estimates of Gross CONE will tend to be more stable, less uncertain, and less dependent on administrative assumptions. Therefore, to minimize the impact of administrative assumptions and uncertainty, it is preferable to choose the economically-viable reference resource type with the lowest E&AS offset. We believe CT technology meets this consideration. While demand resources may have even lower E&AS margins than a CT due to even fewer dispatch hours, there is no standard DR "technology" and its capital costs cannot be determined reliably.

Finally, even if a different technology were to be more economic than a CT under current market conditions, it would be inappropriate to opportunistically switch technologies based on temporary market conditions. While this would reduce average Net CONE values, actual plants do not have an option to switch type, which means no plant would be able to fully recover its fixed costs in the long run unless additional adjustments were made.

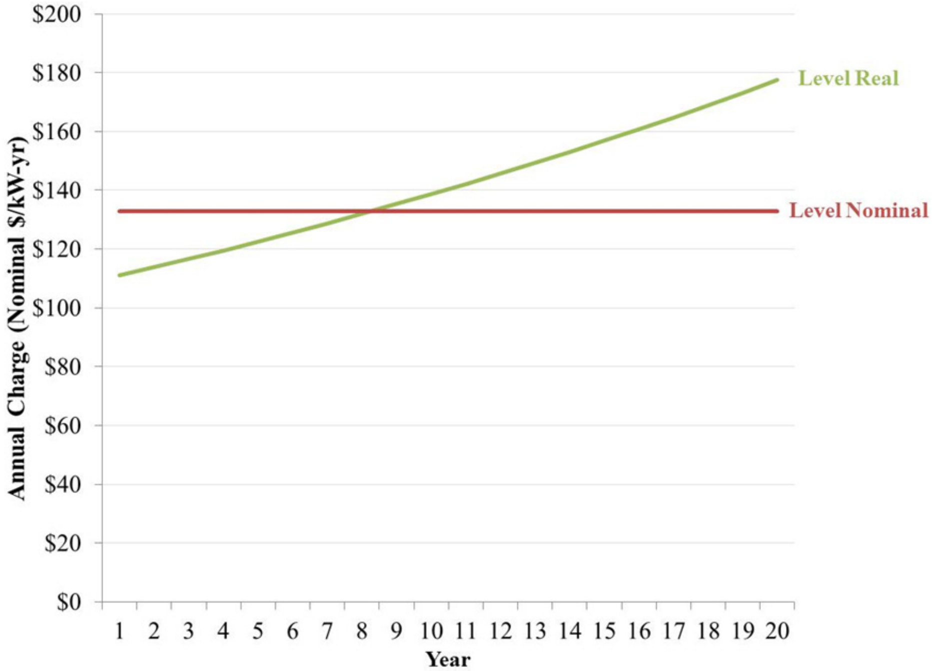
3. The Choice between Real and Nominal Cost Levelization

Translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how annual payments will likely be received over time to cover the investment and other fixed costs of generating plants in a market environment. Figure 14 shows two such possible time paths for our updated cost estimates of a CT in EMAAC as summarized in Table 16. It shows that "level-nominal" cost recovery implies constant annualized gross CONE of $134/kW-year ($367/MW-day) over the entire 20-year cost recovery period. In contrast, the "level-real" cost recovery path for the CT in EMAAC starts at an annual cost of $112/kW-year ($307/MW-day) in the first year, with expected payments in subsequent years increasing at the 2.5% rate of inflation. The present value of these two revenue streams is the same, both being exactly equal to the sum of investment and fixed O&M cost. This means both cost recovery paths provide for full recovery of all fixed costs, including financing costs.

Full cost recovery could also be achieved with cost recovery paths that deviate from the particular slopes of these level-nominal and level-real cost recovery paths. For example, a third levelization option could be based on technology-specific payment trajectory, such as the forecast inflation of CT plants rather than the economy-wide inflation.

The choice among level-nominal, level-real, and this third technology-specific cost recovery profile depends on how RPM-based capacity payments are expected to evolve. For example, if the cost of a CT plant is expected to increase with the rate of inflation—which would mean Net CONE estimates and offers by new entrants would increase at the same rate—investors would anticipate that, on average, RPM capacity prices would increase at that same rate as well. In this case, setting CONE equal to the level-nominal cost for each delivery year over time will over-compensate capacity resources over the course of their economic life. The annual average amount of overcompensation would be approximately equal to the difference between the starting values of the level-nominal and level-real cost recovery paths shown in Figure 14.

Figure 14
Comparison of Cost Recovery Paths for a New CT Plant



If, on the other hand, the cost of new plants and the associated CONE value are expected to increase over time at an average rate equal to the rate of inflation, then setting CONE equal to the starting point of level-real costs for each delivery year would, over time, result in a payment stream that matches the level-real cost recovery requirements exactly. Such an outcome, however, would only be possible if there are no offsetting factors, such as E&AS revenue losses of existing plants relative to increasingly more efficient new plants.

Because CT cost inflation net of E&AS losses relative to new plants may either fall short or exceed general inflation rates, setting CONE equal to level-real costs may under- or overcompensate resources over time. The level-real approach would *under*compensate plants over time if: (1) CT costs increase by less than inflation; or (2) CT costs increase with inflation but CTS built today experience E&AS revenue erosion relative to new CTs built in the future. The level-real approach, however, could *over*compensate if CT cost increases (net of E&AS revenue erosion) exceed general inflation rates. However, if CT costs net of E&AS revenue erosion are expected to increase at all over time, setting CONE equal to level-nominal costs will always overcompensate new plants over time.

To develop a recommendation concerning the choice between these levelization approaches, we have further explored these factors. We first compared the cost trends for CT and CC plants over time by comparing the annual increases of the Handy-Whitman index for turbogenerators with annual inflation rates from the consumer price index (CPI). As Table 18 shows, the annual average cost increases for turbine generators been approximately equal to inflation over the last 50 years, approximately 60 basis points above average inflation rates over the last 20 years, and approximately 150 basis points above inflation over the last 10 years. Note, however, that the rate of cost increase over the last 10 years has not been constant: CT costs have increased much faster between 2003 and 2008, but have decreased since then.

Table 18
Comparison of Inflation Rates and Average Annual CT Cost Increases

Period	U.S. CPI (%)	Handy-Whitman Index: Steam Plant (%)	Handy-Whitman Index: Turbogenerator (%)
1960 - 2010	4.07%	4.57%	4.09%
1990 - 2010	2.73%	3.43%	3.36%
2000 - 2010	2.48%	4.13%	4.02%

Sources and Notes:
U.S. CPI from U.S. Department of Labor (2011).
Handy-Whitman Index (2010).

We are not able to offer a forecast of the extent to which CT cost inflation will differ from general inflation, but we believe that the average rate over the last 20 years may be a useful proxy for the 20-year cost recovery period of new power plants. This would imply average anticipated plant cost increases of approximately 60 basis point above general inflation rates—although this historical rate may understate future CT cost increases. Some of the industry experts we consulted have expressed the opinion that, after the recent economy-related declines in plant costs, CT cost increases looking forward will likely continue to exceed general inflation rates due to the continued rapid demand growth for steel and power plants in large developing economies such as China and India. Increasing environmental requirements may further add to plant cost increases looking forward.

For the purpose of selecting a cost recovery path for determining CONE, we also analyzed the extent to which older plants may see an erosion of E&AS margins relative to the new plants over time. To assess this issue, we analyzed average heat rates for CT plants built over the last 20 years and found a linear trend of annual average heat rate decreases (*i.e.*, improvements) of approximately 100 Btu/kWh a year. We estimated that this rate of technological progress is equivalent to an E&AS revenue erosion rate of approximately 50 basis points (*i.e.*, 0.5 percentage points) per year. This means that CT cost increases at a rate slightly above average inflation rates (approximately 60 basis points per year) is almost entirely offset by the effects of E&AS erosion due to technological progress (approximately 50 basis points per year).

The net effect of these two offsetting factors means that new CT plants built today can be expected to achieve a cost recovery path that increases approximately at the rate of inflation. As a result, we believe that levelized carrying charges based on a level-real cost recovery are most appropriate for determining the annualized estimate of CONE. We recognize that PJM's current use of level-nominal charge rate (implicitly assuming level-nominal cost recovery) has been the result of extensive stakeholder and settlement discussions. The level-nominal carrying charge approach has also been approved by FERC. Nevertheless, we believe that the level-nominal approach to determining CONE, if combined with accurate estimates of E&AS margins, will result in the VRR curve being anchored at a level that exceeds the average annual cost recovery needs over new plants over time—the end result of which will be over-procurement of resources relative to the reliability target.

We thus recommend that PJM and its stakeholders consider transitioning from the current level-nominal CONE to a level-real CONE. A level-real approach to calculating carrying charges is more consistent with the historical escalation of new plant costs when adjusted for the improved performance of new plants. Continued increases in net plant costs can be expected to support increasing capacity market prices going forward and allow present-day developers to earn net revenues that grow with inflation (*i.e.*, at a constant rate in "real" dollar terms.)

This recommendation is contingent, however, on combining it with our recommendations that resolve two important factors: (1) the calibration of the current methodology for calculating the E&AS offset, which currently overstates the E&AS margins actually earned by comparable CT plants in eastern PJM and thus creates a downward bias in Net CONE estimates (see next subsection); and (2) the potential VRR curve performance concerns related to the use of historical E&AS averages (*e.g.*, if historical E&AS offsets were to spike due to anomalous weather or outages). As discussed in Section V, we recommend raising the price cap (defined as "point a" on the VRR curve), which is particularly important if PJM and stakeholders are unable to develop a forward-looking approach to calculating E&AS offsets.

If the approach to determining the administrative E&AS offset is not adjusted and the potential VRR performance concerns are not addressed, maintaining the current level-nominal carrying charges to determine CONE will help address—at least in part, though likely inefficiently—these other concerns. The same conclusion, however, does not apply for defining the offer threshold in the MOPR. We believe level-real annualization is more consistent with market fundamentals and competitive bidding behavior. As a result, we recommend against retaining the level-nominal approach for CC and CT offer thresholds under the MOPRs.

4. Summary of CONE Recommendations

To summarize, we offer the following recommendations related to the choice and cost of reference technologies:

- ***Reference Resource Type*** — We recommend maintaining a CT as the reference technology for the determination of Net CONE in the VRR curve.

- ***Reference CT and CC Design Features*** — We recommend the CC and CT design features based on an analysis of PJM and U.S. plants currently under construction and the requirement that new plants are capable of meeting likely upcoming NO_X emissions standards. As discussed in more detail above our recommendations include:

  CT — A 390 MW summer capability greenfield plant with 2 GE 7FA.05 turbines with selective catalytic reduction ("SCR") for NO_X controls (but no SCR in the Dominion CONE Area), and evaporative cooling for power augmentation.

  CC — A 2x1 plant using GE 7FA.05 turbines, a cooling tower, SCR, duct firing and evaporative cooling for power augmentation, and a total summer capacity of 656 MW, of which 72 MW is associated with duct firing.

We also offer the following recommendations related to levelized gross CONE values:

- ***Financing Assumptions*** — We recommend using updated financial assumptions to calculate annualized gross CONE. They reflect a merchant generator using balance sheet financing without a power purchase agreement (PPA), using an 8.5% after-tax weighted average cost of capital and 20 year cost recovery as discussed above.

- ***Recommended Levelized Gross CONE estimates for a CT*** — The level-real estimate of gross CONE for a CT and the 2015/16 delivery year in EMAAC is $112/kW-year ($306/MW-day). Based on level-nominal cost recovery, our estimate of gross CONE is $134/kW-year ($367/MW-day). This compares to the inflation-adjusted, currently-used, level-nominal CONE value of $142/kW-year ($389/MW-day). Results for other CONE Areas are provided in Table 16.

- ***Recommended Levelized Gross CONE estimates for a CC* —** Our updated 2015/16 level-real gross CONE estimate for a CC and the 2015/16 delivery year in EMAAC is $141/kW-year ($385/MW-day) based on level-real annualization. Our level-nominal estimate of gross CONE is $168/kW-year ($461/MW-day), compared to the inflation-adjusted, currently-used value of $180/kW-year ($492/MW-day). Results for other CONE Areas are provided in Table 17.

- ***Levelization Method*** — We recommend that PJM and stakeholders consider transitioning from the current "level-nominal" to a "level-real" levelization approach. This is consistent with average CT cost inflation over the last 20 years (inflation plus 60 basis points) net of an offset from heat rate improvements (approximately 50 basis points). Our recommendation for CT costs to define the VRR curve is contingent on combining it with our recommendation related to the E&AS offset and potential VRR curve performance concerns as discussed below. Our recommendation to transitioning to a level-real approach for MOPR purposes is not contingent upon adopting other recommendations.

B. ENERGY AND ANCILLARY SERVICE OFFSET

To determine Net CONE for the purpose of "anchoring" the VRR curve, the administratively-determined CONE value is reduced by the E&AS offsets earned by the reference technology. This E&AS offset represents an estimate of the "margin" (revenues in excess of variable generation costs) that a new entrant with the reference technology earns from the sale of energy and ancillary services. Under current RPM rules, E&AS offsets are calculated as a three-year average of estimated historical margins for the reference technology.

We address three key questions related to the administrative E&AS offset: (1) How accurate is the administrative calculation of E&AS margins relative to what is actually earned by generators similar to the reference technology? (2) Should the offset be based on a historical or a forward-looking estimate? And (3) how should administratively-set scarcity prices be accounted for in the E&AS offset?

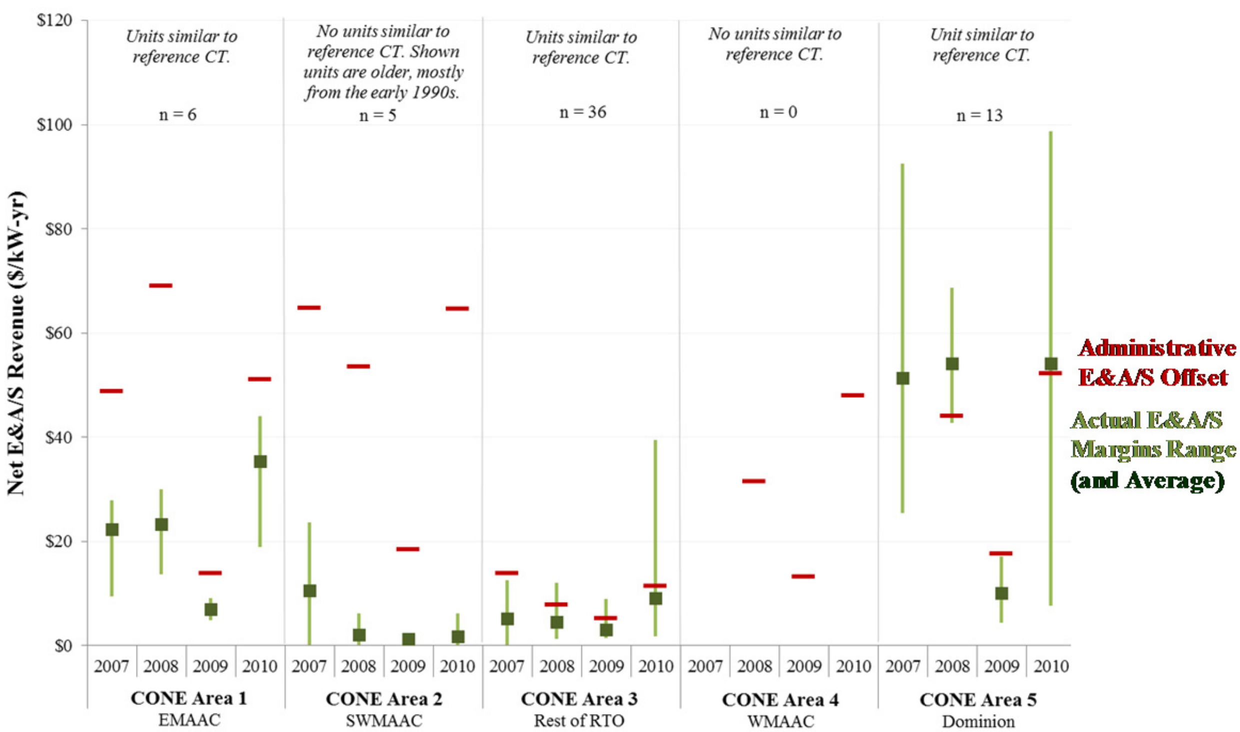
As we explain in more detail, we find that the methodology used to determine the E&AS offset significantly overstates E&AS margins and recommend adjustments to align the E&AS offset more closely with actual E&AS margins. We are also concerned about price volatility and poor price signals associated with relying on historical E&AS offsets, and we recommend that PJM and its stakeholders continue to explore options for forward-looking or an "equilibrium-based" E&AS offset methodology. Finally, we recommend against any netting or other adjustments to energy scarcity revenues actually earned in the energy market.

1. Accuracy of Administrative Historical E&AS Offset

PJM's methodology to estimate E&AS margins uses the "Peak-Hour Dispatch" method and a set of assumptions regarding heat rates, costs, and fuel prices.[105] Under the "Peak-Hour Dispatch" method, the reference resource may be dispatched into the real-time energy market in four independent, four-hour blocks (between hour ending 8:00 and hour ending 23:00) each day. Each block is dispatched if the average real-time LMP is high enough to cover the cost of operation for at least two hours in the given block. The resulting simulated generation pattern and the corresponding revenues net of operating costs yield the E&AS offset for the reference resource.

Figure 15 compares the administratively-determined E&AS offset for CTs with the E&AS margins actually earned by CT units similar to the reference resource in each CONE area. Figure 16 shows the same comparison for CC plants. These comparisons show that the administrative calculation of the E&AS offset determined for historical years has been substantially higher than the E&AS margins actually earned by comparable plants during these years.

Figure 15
Administratively-determined and Actual E&AS Margin of <u>Combustion Turbine</u> Plant

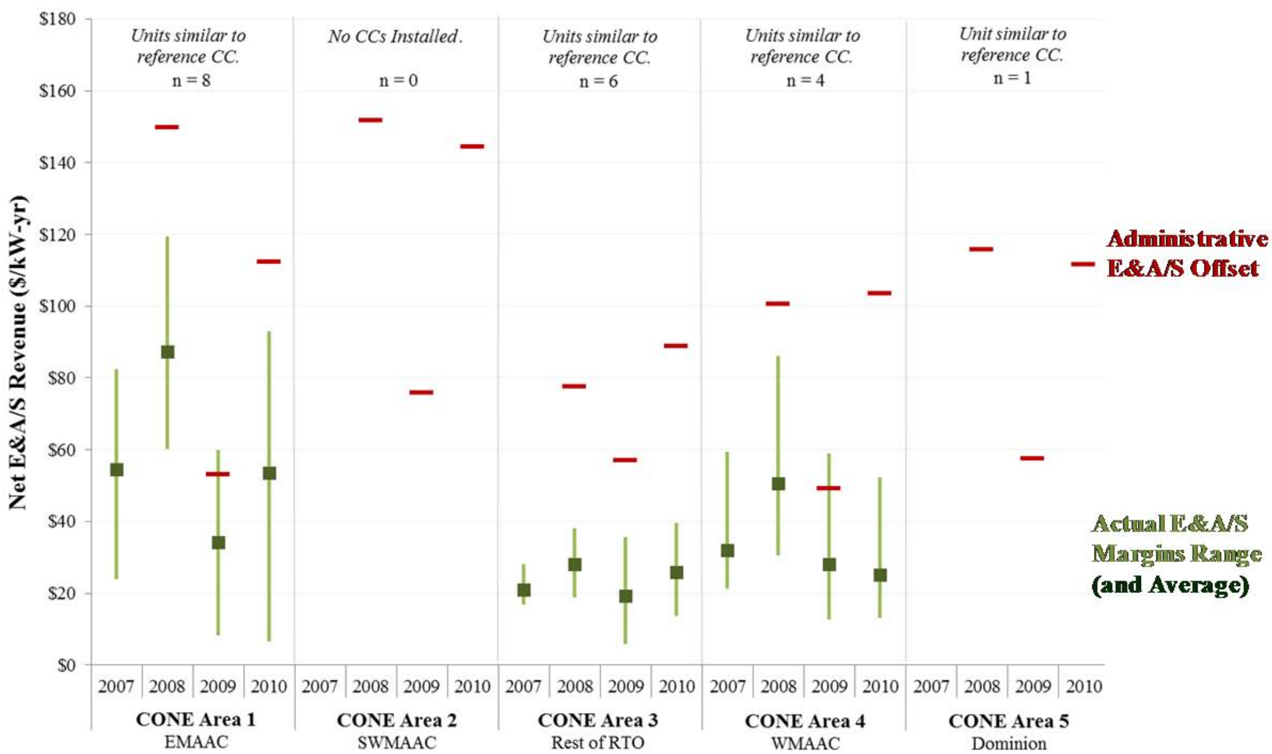


As shown in Figure 15 for CT plants, the administrative offset is substantially higher than actual CT margins in EMAAC and higher than all but the highest margins for some of the plants in the Rest of RTO Area. The E&AS offset for CTs is relatively accurate in Dominion. New CT plants comparable to the reference technology are not available in the other CONE Areas, but actual E&AS margins earned by older CT plants in SWMAAC and WMAAC suggest that the

105 The E&AS calculations assume a heat rate of 10,500 BTU/kWh, variable O&M expenses of $5/MWh, $2,254/MW-year ancillary service revenues, and use actual fuel and hourly electricity prices.

administratively-determined E&AS offset may be significantly overstated in SWMAAC but approximately right in WMAAC.

Figure 16
Administratively-determined and Actual E&AS Margin of Combined-Cycle Plant



The discrepancy between administratively-determined E&AS offsets and actual E&AS margins is shown in Figure 15. This discrepancy is likely driven by three main factors: (1) the peak-hour dispatch methodology only uses real-time prices, which is not consistent with the fact that the majority revenues are obtained through day-ahead commitments, even for CTs; (2) the E&AS offset for CTs is determined based on the average LMP for the zone in the CONE region for which the gross CONE value was developed, which may not be representative of locations where plants are actually built; for CCs (used for MOPR purposes) the E&AS offset is based on the highest-priced zone within the CONE Area, which is not necessarily a location where generators are able to site new plants or build them at a cost-effective rate; and (3) dispatch costs of actual plants may be higher than estimated for a variety of reasons.

The first of these three factors may account for a significant portion of the observed differences. It is generally understood that CC plants earn most of their revenues in the day-ahead market. However, as PJM's independent market monitor has previously noted, even new CT plants similar to the reference technology earn only approximately 40% of their energy revenues in the day-ahead market,[106] compared to 100% assumed in the current dispatch methodology. The dispatch logic should attempt to replicate realistic participation in both the day-ahead and real-time energy markets.

[106] Joseph Bowring, "CT Revenues: Day Ahead vs. Real-Time," CMEC, September 29, 2009, p. 6.

In addition, based on preliminary research provided to us by PJM's independent market monitor, the actual dispatch costs of CTs and CCs may be higher than assumed in the administrative calculations due to factors such as penalty gas charges, fuel oil consumption of dual-fuel plants during periods of limited gas availability, and less efficient heat rates. Based on information provided by the IMM, for example, in some load zones with CTs that experience natural gas deliverability issues, average operating costs were 150 percent higher in 2010 due to fuel switching and the high cost of fuel oil compared to natural gas. Actual E&AS margins may also be lower than estimated due to other plant-specific factors such as local transmission limitations or operating limitations (*e.g.*, 24 hour minimum run times) which make dispatch less attractive and operations less profitable.

There are also some examples of CT and CC plants with actual E&AS margins that are close to or above the administratively-determined E&AS offset. On average, however, the available data suggests that the administratively-determined E&AS offset unrealistically overstates the E&AS margins actually available to new plants. All else equal, this will downward bias the VRR curve and lead to under-procurement of capacity resources relative to reliability targets. As discussed further in Section V of our report, discrepancies between the administratively-determined E&AS offset and the margins that market participants can actually expect to earn with new plants could also lead to outcomes in which the actual cost of new entry exceeds the cap of the VRR curve, deterring needed entry.

We therefore recommend that PJM and its stakeholders more fully evaluate and, if necessary, address the identified concern of overstated E&AS offsets. To avoid such overstated E&AS offsets, we recommend tying the administrative calculation of E&AS revenues more closely to the margins actually earned by resources similar to the reference resource in the day-ahead, real-time, and AS markets. This can be achieved by revising and calibrating the dispatch algorithm so that it accurately reflects actual units' revenues and operating costs within the respective CONE areas. A revised dispatch algorithm could address day-ahead versus real-time dispatch and possibly also improve operating cost and fuel type assumptions. Alternately, it can be achieved by calculating the E&AS offset directly from the net revenues of comparable new units (but avoiding distortions due to idiosyncratic factors affecting individual units).

The location of units and associated generation-specific LMPs used to determine the E&AS offset for each CONE area ideally should be selected using the same principle as in our CONE Report: based on locations that have been demonstrated to support new development, as evidenced by recent and ongoing development of actual plants. The availability of operational plants also enables calibration of the E&AS dispatch methodology. For areas that lack such units, such as SWMAAC, direct calibration may not be possible, but the dispatch algorithm calibrated to other areas could be applied.

2. Historical, Forward-Looking and "Equilibrium" E&AS Offsets

We noted in our 2008 Report that estimation errors for Net CONE have consequences for both reliability and customer costs, although these impacts are partially mitigated by the downward-sloping nature of the VRR curve. If the "true" cost of new resources is above the administratively-determined Net CONE, fewer resources will be procured through RPM than what is needed to meet reliability targets. If the true cost of new entry is below Net CONE, RPM will over-procure relative to reliability targets.

The E&AS offset strongly affects the accuracy of the Net CONE estimate. It is difficult to develop estimates that will be consistent with generation developers' actual expectations. As we also noted in our 2008 Report, Net CONE estimation errors are magnified by the use of a historical E&AS offset. This is because anticipated E&AS revenues will vary with market conditions that will not generally be consistent with the E&AS offset that PJM calculates based on historical data. Using an historical E&AS offset to determine Net CONE and the VRR curve can thus lead to uneconomic and inaccurate price signals. Moreover, as we discuss further in Section V of our report, our probabilistic analyses show that the use of a historical E&AS offset can lead to substantial performance deterioration of the VRR curve that can undermine investment incentives and make it difficult to achieve reliability targets. It also needs to be considered that historical E&AS offsets within constrained LDAs can significantly exceed anticipated future E&AS offsets, which may reflect reduced future congestion premiums caused by the planned construction of new generation and transmission upgrades into the LDA.

An E&AS offset can be consistent with developers' expectations only if it accounts for anticipated changes in market fundamentals. The current use of an administratively-determined E&AS offset based on a 3-year average of historical market conditions means that the data used to determine the offset is between four to seven years out of date relative to market conditions during the delivery year. The reliance on historical market conditions will also increase RPM price volatility and pricing discrepancies between LDA areas simply because the E&AS offset will be influenced by unusual historic market conditions, such as extreme weather or unusual generation and transmission outages. Such events can lead to spikes in the administratively-determined E&AS offset that not only lead to capacity price volatility, but are also are inconsistent with forward-looking market conditions even if there are no other material changes in market conditions. Even based on the RPM experience to date, which does not yet include any years of exceptionally challenging market conditions, the variance of E&AS offsets has been considerable. In SWMAAC, for example, the administratively-determined E&AS offset increased from $57/MW-day for the 2009/10 delivery year to $154/MW-day for the 2012/13 delivery year.

In addition, the reliance on actual historical market conditions can lead to capacity prices that undermine efficient investment incentives. For example, the most resource-constrained locations with the greatest investment needs will tend to have the highest energy market prices, which lead to high E&AS offsets. These higher E&AS offsets will lower Net CONE. If market participants' expected future E&AS margins are below these historical margins (for example, reflecting an expectation of resource additions or transmission upgrades), their true net cost of new entry will be above the administratively-determined Net CONE, which will mean fewer resources will be procured through the RPM mechanism. On the other hand, in locations with excess capacity, historical E&AS offsets will generally be low, which leads to a higher Net CONE and stronger investment incentives. In other words, the use of E&AS offsets based on historical market conditions will tend to reduce investment incentives in LDAs with higher investment needs while increasing investment incentives in LDAs with lower investment needs. Price spikes caused by shortages (even if only caused by unusual weather or outage conditions) reduce the administrative Net CONE and VRR curve exactly when and where new investments are needed most.

Such outcomes are not only a theoretical possibility. For example, during the last three BRAs the E&AS offsets for LDAs in eastern PJM were between $130-150/MW-day, which was approximately *$100/MW-day higher* than the E&AS offset for the rest of PJM. If the E&AS margin anticipated by market participants for eastern PJM was *half* the historical value, the VRR-curve-based price signal sent in the more constrained eastern LDAs would be understated by about $65-75/MW-day. In more extreme cases of high historical energy market prices due to unusual market conditions and resource needs, this potential disconnect between the historical administrative E&AS offset and the anticipated future E&AS margins of market participants could even result in outcomes where the true cost of new entry exceeds the cap of the VRR curve, which leads to RPM performance problems as further discussed in Section V.[107]

Options to mitigate some of the price distortions caused by the use of historical E&AS offsets based on actual market conditions include the use of (1) normalized forward-looking E&AS offsets that reflect normalized weather and outage conditions as well as anticipated resource additions; and (2) E&AS offsets estimated based on equilibrium market conditions, which would also reduce price distortions caused by temporary shortage or excess capacity conditions. Any form of forward-looking E&AS offsets would improve VRR curve performance and more stable capacity prices that better reflect anticipated market conditions.

One approach to estimating such forward-looking E&AS offsets would be to develop forecasts based on detailed market simulations, for example, by calibrating a simulation model to current market conditions and then modifying the data inputs to reflect changes in fuel prices, supply, demand, and transmission that will likely exist during the delivery year. We recognize, however, that FERC rejected PJM's proposal to develop its own forecasts on the basis that such forecasts may be too speculative. In addition, simulation-based forecasts may not be sufficiently transparent and reproducible by market participants. Nevertheless, an E&AS offset estimate consistent with "equilibrium market conditions" (rather than forecast or historical conditions) would stabilize the VRR curve and anchor it at a Net CONE level that is consistent with target equilibrium capacity prices and corresponding E&AS margins. (Such an equilibrium E&AS offset approach would also be consistent with Prof. Hobbs's probabilistic simulations of the settlement curve.) An alternative could be to develop estimates of forward-looking E&AS margins from forward prices for fuel and power. However, we also recognize that PJM and its stakeholders already explored this option in 2008 but were not able to identify an acceptable methodology.

In summary, we believe that the disadvantages of using an administratively-determined E&AS offset based on historical market conditions are significant. As a result, we recommend that PJM and its stakeholders continue to consider options to develop acceptable forward-looking or equilibrium-based methodologies to determine the E&AS offset. If a forward-looking offset cannot be developed, it is critical to increase the cap of the VRR curve to mitigate the most significant risks associated with historical E&AS offsets as discussed in Section V.

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107 For example, assume CONE=400/MW-day and the historical E&AS offset is $250/MW-day, such that the administratively-determined Net CONE = $400 - $250 = $150/MW-day. The VRR curve would be capped at $225/MW-day or 1.5×Net CONE. If the anticipated future E&AS margin was only $150/MW-day (*e.g.*, due to anticipated resource additions relative to the historical period and unusual weather and outage conditions during the historical period), the "true" net cost of new entry would be $250/MW-day (*i.e.*, $400-150).

3. Scarcity Pricing and Energy True-Up Options

As discussed above, we recommend that the E&AS offset reflect E&AS margins earned by a CT plant under equilibrium or expected normalized forward conditions. This should include margins associated with price spikes and administratively-determined scarcity pricing. We do not recommend excising scarcity prices from the administratively-determined E&AS offsets (thus raising Net CONE and capacity prices); nor do we recommend netting out any scarcity prices actually earned in the delivery year, as suggested by the IMM.[108] Doing so would reduce incentives for resources to perform during actual scarcity conditions when they are needed most. It would also distort price signals for capacity resources that are dispatched more often or less frequently than the reference technology for which CONE and E&AS offsets are determined. Instead of reducing E&AS volatility by excluding scarcity events from the determination of the E&AS offset, we recommend in Section V options for refining the VRR curve to mitigate the most significant risks associated with the higher volatility of historical E&AS offsets.

4. Summary of E&AS Offset Recommendations

As discussed above, we recommend that PJM and its stakeholders consider the following recommendations:

- ***Increase the Accuracy of the E&AS Offset* —** We recommend that the calculation of the E&AS offset be improved to better reflect actual E&AS margins earned by plants similar to the reference unit through either (a) calibrating the dispatch algorithm so that it accurately reflects actual units' net revenues (e.g., significant participation in day-ahead markets even by CTs) or (b) that the E&AS offset be calculated directly from the net revenues of comparable new units.

- ***Forward-Looking or Equilibrium Net CONE Estimate* —** We recognize that PJM and its stakeholders have previously explored developing a forward-looking E&AS offset but were not able to identify an acceptable methodology. However, we recommend that PJM and its stakeholders continue exploring options for forward looking or "equilibrium-based" E&AS offsets because these options would offer improved VRR curve performance and yield more stable capacity prices that better reflect future or equilibrium market conditions.

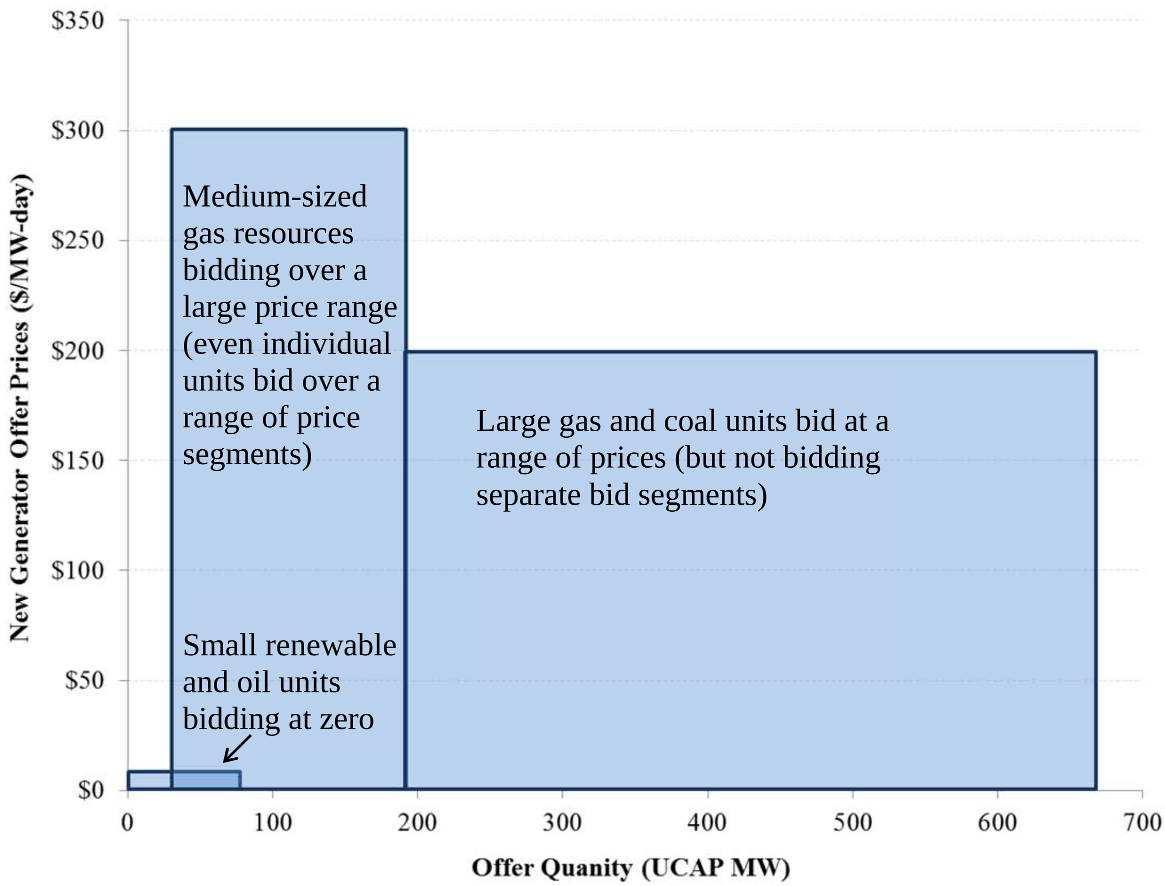
- ***Treatment of Scarcity Pricing* —** We recommend that the E&AS offset include the historical (if historical E&AS offsets continue to be used) or expected future level of scarcity revenues from the energy and ancillary service markets. We recommend against any netting or other adjustment of energy scarcity revenues actually earned in the energy market.

[108] Note, however, if scarcity events are excluded out in administratively-determined historical E&AS offsets, it would also be necessary to net out actual or typical margins earned due to scarcity prices during the delivery period. Implementing the former without the latter would overcompensate resources or lead to over-procurement.

C. Empirical Net CONE from Bid Data

We reviewed all offers for new generating units and found that offer levels vary substantially, with the overall range of these offer prices and sizes shown in Figure 4. Most of these bids are for small renewable and diesel resources that offered in at a zero price. However, natural-gas-fired generation projects have similarly submitted offers at a large range of prices, both above and well below Net CONE. Some individual units have even offered sections of their capacity over a large range of prices. Although we do not know the ultimate cost- or non-cost justification behind the wide range of bids for new natural gas units, offers seem to reflect a wide range of different bidding, hedging, and market-timing strategies. Based on these results of our analysis, we conclude that BRA offer data does not provide a sound basis for determining Net CONE empirically from offers for new resources.

Figure 17
Offers for New Generation in PJM



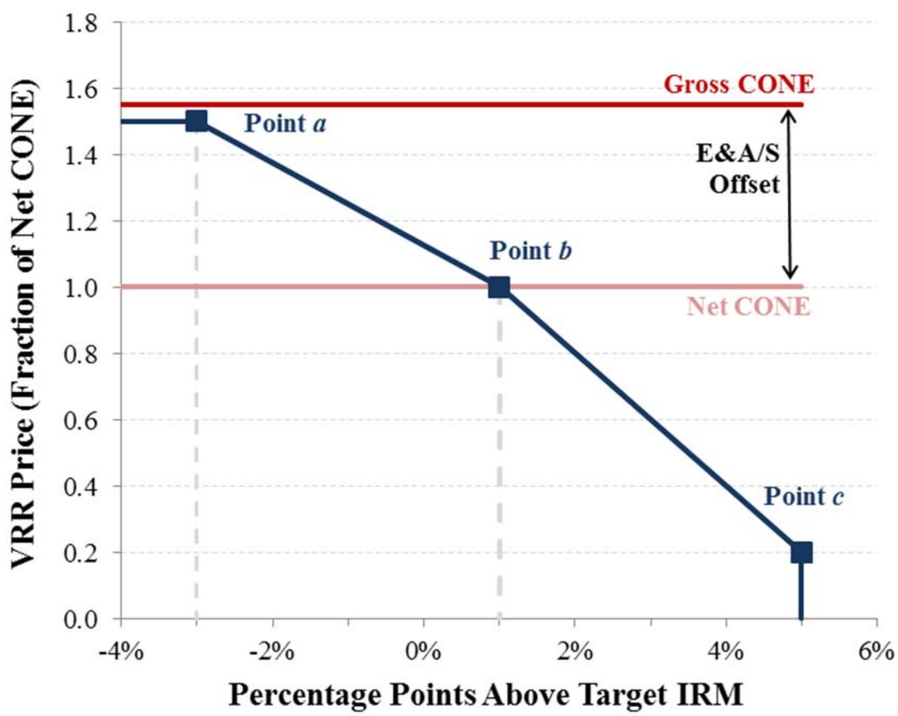
Sources and Notes:
Summarized from BRA and IA bid data, PJM (2011a).
Offer quantity is based on the total bid MW for each unit across all offer segments.
Offer price is the range of prices for each unit across all offer segments.

V. ANALYSIS OF VARIABLE RESOURCE REQUIREMENT CURVE

A. BACKGROUND

As explained in more detail in our 2008 report, the VRR curve represents the administratively-determined demand for capacity in the RPM auctions.[109] Figure 18 shows that the VRR curve, which was the result of settlement discussions among stakeholders, is anchored around point *b*, with the price equal to Net CONE and the capacity procured is at the target installed reserve margin ("IRM") plus 1 percentage point (IRM+1%).[110] From this anchor point, the VRR curve slopes upward and to the left until it is capped at point *a*, which is at a quantity of IRM - 3% and a price of 1.5 times Net CONE. For clearing prices below Net CONE, the curve drops to point *c*, at IRM + 5% and a price of 0.2 times Net CONE.

Figure 18
PJM Variable Resource Requirement (VRR) Curve



Sources and Notes:
Based on 2014/15 SWMAAC VRR curve parameters, PJM (2011b).

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[109] See Pfeifenberger and Newell, *et al.* (2008), Section IV; PJM (2011d), Section 3.4.

[110] That is, if the target installed reserve margin is 15.3% (as it was in the 2014/15 BRA), then the quantity at point *b* is equivalent to an IRM of 16.3%. This represents a procurement quantity of 0.9% on top of the reliability requirement based on the year 2014/15 parameters. The exact quantity calculation at point *b* is: Reliability Requirement · (100% + IRM + 1%) / (100% + IRM) – STRPT. See PJM (2011d), p. 19; (2011b).

During the first five BRAs, the VRR curve was shifted to the left of IRM+1% by the estimated amount of ILR resources obtained just prior to the delivery year. Since ILR was eliminated, starting with the BRA for the 2012/13 delivery year, the entire VRR curve is shifted to the left by the Short-Term Resource Procurement Target (STRPT). In the BRA, the STRPT is equal to 2.5% of the reliability requirement.[111]

In our 2008 RPM report, we evaluated the shape and performance of the VRR, both qualitatively and through simulations with a probabilistic model originally developed by Professor Benjamin Hobbs.[112] That analysis compared the VRR curve as currently implemented in RPM through a stakeholder settlement (the "Settlement Curve") with the VRR curve that was originally developed and filed by PJM with Prof. Hobbs's input and testimony (the "Original Hobbs Curve"). Our 2008 probabilistic simulation analysis evaluated: (1) the impact of conducting the auctions three versus four years ahead of delivery; (2) the impact of using historical average for the E&AS offset versus projected E&AS offset; (3) the impact of understating or overstating CONE; (4) the impacts of CONE changes due to changes in construction costs; and (5) the performance of the sloped VRR curve versus a vertical demand curve.[113] Based on these analyses, we previously offered a number of recommendations for further consideration by PJM and its stakeholders. These recommendations included maintaining the 3-year forward auction design, maintaining the shape of the VRR curve, and moving to a forward-looking E&AS offset.

In our current examination of the VRR curve, we evaluated the performance of the VRR curve qualitatively, with updated probabilistic simulations, and using scenario analyses of historical auction results. This led us to revisit some of the same questions we have previously examined as well as examining some additional questions as follows.

First, and perhaps most importantly, we address our previous finding that the Settlement Curve with a historical E&AS offset performed poorly in our probabilistic simulations in terms of long-term resource adequacy, which contributed to our previous recommendation to move to a forward-looking E&AS offset. Because the stakeholder process that explored this option in 2008 was not able to identify an acceptable forward-looking E&AS offset methodology, we now explore alternatives that would improve the performance of the Settlement Curve when using historical E&AS offsets.

Second, we examine the impact that the current point *a* definition has already had. We document that E&AS offsets have already problematically suppressed the VRR curve in constrained LDAs, which could have led to a failure to procure an adequate level of location-specific resources.

Third, we present updated results of our probabilistic simulations with the model developed by Prof. Hobbs. The results from these analyses document the poor performance of the Settlement Curve in combination with historical E&AS offsets. We also present simulation results for four alternative definitions of point *a* in the current VRR curve that could significantly improve the performance of the VRR curve.

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[111] The STRPT as a percent of the reliability target is 2% in the first incremental auction, 1.5% in the second incremental auction, and 0% in the third incremental auction.

[112] For a description of the Hobbs model as developed and used to develop the original VRR curve, see Hobbs (2005, 2007).

[113] See Pfeifenberger and Newell, *et al.* (2008), Section IV.C.

Finally, we explore the impact that a vertical demand curve or a flatter VRR curve would have had on RTO and LDA clearing prices during the first seven BRAs. We also explore whether less steep VRR curves applied to LDAs would be an effective tool to attract investment and reduce capacity price volatility within the LDAs. We document that price volatility experienced in BRAs to date would have been significantly higher with a vertical supply curve, but find that a more gradual VRR curve would not have significantly reduced capacity price volatility. We also recommend against applying a more gradual slope selectively in constrained LDAs because this would increase the risk of under-procurement without substantially reducing price uncertainty.

B. Impact of Historical E&AS Offset and Net CONE Estimation Error

In our 2008 simulations, we identified a number of concerns related to using a historical E&AS offset and the impact of potentially understated administrative CONE estimates. More specifically, we found that the use of historical E&AS averages could lead to "resonances" with highly unstable Net CONE values and result in high total costs, high price volatility, and poor reliability. We also found that the VRR curve performed poorly if the Net CONE value used to anchor the VRR curve was below the true value of Net CONE, causing reliability challenges, higher costs, and higher volatility as clearing prices more frequently reached the capped portion of the VRR curve.

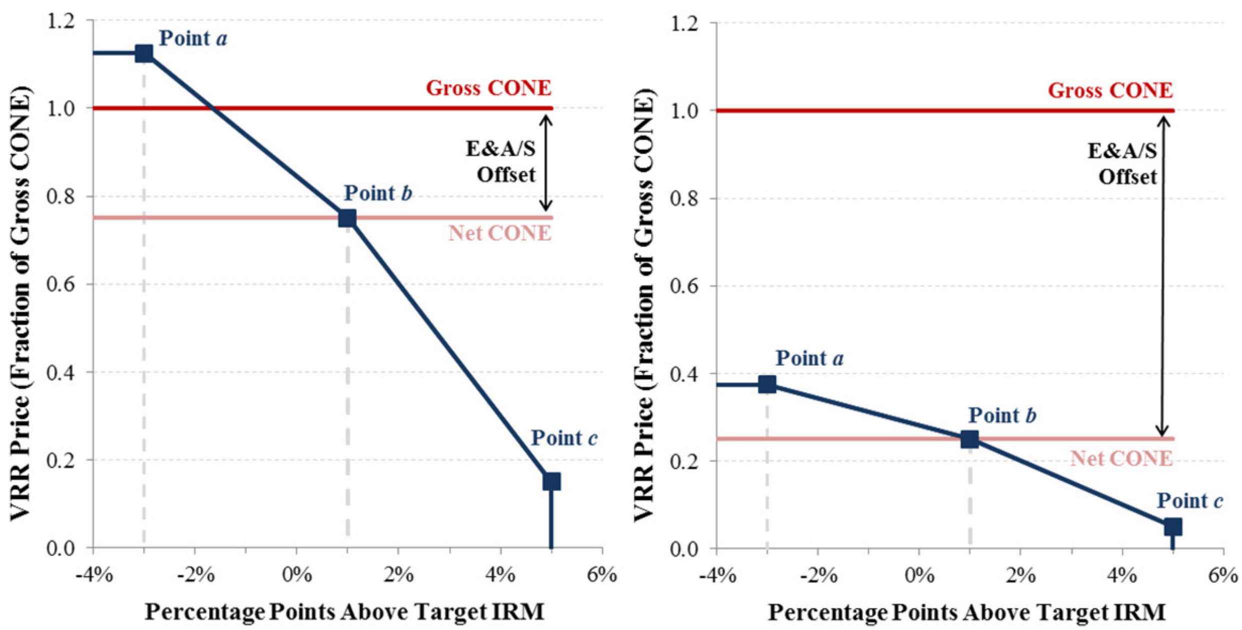
To address these concerns, we previously recommended that PJM and stakeholders consider: (1) determining the E&AS offset to gross CONE based on estimated future E&AS margins; and (2) whether restrictions to the magnitude of annual Net CONE changes should be introduced. A stakeholder process initiated by PJM subsequently explored options for forward-looking E&AS offsets, but found that proposed options were not sufficiently accurate, robust, or transparent enough to offer an acceptable alternative to using historical E&AS offsets. As we discuss in Section IV.B, we renew our recommendation to explore options for determining the E&AS offset based on either normalized forward-looking market conditions or based on estimated offset under "equilibrium market conditions." However, recognizing that a forward-looking E&AS offset methodology that stakeholders found acceptable could not be developed in 2008, we now also analyze other options for addressing the identified performance concerns of relying on the current Settlement Curve combined with historical E&AS offsets.

Our first step was to develop a better understanding of why reliance on historical E&AS averages resulted in poor performance in terms of simulated cost and reliability outcomes. We found that the poor performance of the Settlement Curve in simulations with a historical E&AS offset were primarily a function of: (1) how the price cap at point *a* of the VRR curve is defined and (2) how quickly Net CONE values can drop over time in response to volatile energy market conditions.

The VRR curve is currently capped at point *a* at 1.5 times Net CONE. Because Net CONE declines whenever historical E&AS offsets are high, the price cap (at point *a*) will decline 1.5 times as fast as the E&AS offset increases. In other words, the higher the historical E&AS offset, the lower the price cap and the slope of the VRR curve between points *a* and *b*. If the level of historical E&AS offset ever reaches or exceeds gross CONE, both Net CONE and the slope of the VRR curve will drop to zero. At that point the VRR curve, collapsed to zero, can no longer provide any incentive to add resources even if reserve margins drop well below the reliability target. Entry in this case would be solely a function of high and volatile E&AS margins. Even if the average E&AS offset is equal to CONE at that point, the system can become "stuck" at a reserve margin well below the reliability target because no additional investment incentives would be provided by the VRR curve to attract entry and move the system back to the target reserve margin.

The two panels in Figure 19 illustrate the shape and slope of the VRR curve for historical E&AS margins that are equal to 75% and 25% of gross CONE. It shows that if the E&AS offset is equal to 75% of gross CONE, such that Net CONE is only 25% of gross CONE, the VRR curve is capped at 38% of CONE. This also means that the difference between point *b* and point *a* is only 13% of CONE. This difference is well below the extent to which the administrative value of Net CONE (used to define point *b* of the VRR curve) can differ from the "true" Net CONE that suppliers may forecast for the delivery year. That is, the true net cost of entry could easily be higher than the price cap on a sustained basis or in a large fraction of years due to fluctuations in the energy market. If RPM prices are capped below the true net cost of new entry, the outcome will be fewer capacity additions and lower reliability.

Figure 19
VRR Curves with E&AS Offset Equal to 25% and 75% of CONE



Note: Procurement target is defined as the reliability requirement minus the short-term procurement target.

The potential for low reliability with the current VRR curve is exacerbated by the asymmetric nature of the curve. The VRR curve slope to the left of point *b* is flatter than to the right of point *b*, with prices rising only slowly in response to dropping reserve margins. Another asymmetry is that RPM prices can only rise 0.5 times above Net CONE, whereas they can drop as low as zero (*i.e.*, a level 1.0 times below Net CONE). The practical result of this asymmetry is that one should expect capacity prices to average at a level below Net CONE if the reserve margin were to be maintained. This means that reserve margins must drop below the target in order for the VRR curve to produce prices that are consistent with Net CONE on average over the long term. The fact that the VRR curve is anchored at the reliability target plus 1 percentage point helps offset some of this asymmetry in VRR curve slopes.

The historical E&AS offset used to determine Net CONE has ranged from a low of 9% of gross CONE (in the 2014/15 BRA for the unconstrained RTO) to a high of 48% of gross CONE (for the 2010/11 BRA in SWMAAC) since RPM was implemented. While this means that E&AS offsets have not yet reached levels close to CONE, the experience to date has not yet included delivery years with resource adequacy deficiency, unusual price spikes due to extreme weather conditions, or unusual generation and transmission outages that could increase the E&AS margins earned by a peaking plant to levels well above the value of gross CONE. As more demand response resources with high dispatch costs are added to the system, we also anticipate that the E&AS revenues of peaking plants will increase over time—which will flatten the VRR curve and increase the risk that the VRR curve collapses entirely and resource adequacy can no longer be ensured through RPM.

The definition of the current VRR curve cap may have been an inadvertent outcome of the VRR curve settlement. The curve originally filed by PJM, based on Prof. Hobbs recommendation, was capped at two times gross CONE minus the E&AS offset. This is equal to the sum of Net CONE *plus* gross CONE, which meant that the difference between points "a" and "b" was equal to CONE irrespective of the size of the E&AS offset.[114] The settlement reduced the cap (point *a*) to 1.5 times Net CONE, which is equal to 1.5 times gross CONE minus 1.5 times the E&AS offset.[115] The problem associated with the flattening VRR curve and the possibility that point *a* collapses to zero would not exist if the factor of 1.5 were only applied to the gross CONE portion. In other words, if point *a* was defined as "1.5×CONE – E&AS" instead of "1.5×(CONE – E&AS)," the difference between points *a* and *b* would be equal to 0.5×CONE and remain constant even if point "b" declined to zero.[116]

As discussed further below, the probabilistic simulations show that the performance deterioration of the Settlement Curve in assuring resource adequacy is very pronounced if a constant or forward-looking E&AS offset is replaced with a historical E&AS offset. However, because these simulations are quite stylized, it is not clear how high the risk of such outcomes would actually be under real-world conditions. Nevertheless, to reduce the risks of resource adequacy challenges due to a collapsing VRR curve or a VRR curve capped at a level below the true net cost of new entry, we recommend that PJM and its stakeholders reconsider developing a normalized forward-looking or equilibrium offset. If not, we recommend that PJM and its stakeholders consider and more fully evaluate the following combination of recommendations:

- ***Clarify that the value of Net CONE for purpose of defining points a, b and c of the VRR curve cannot be less than zero.*** In cases where historical E&AS offset would exceed CONE, Net CONE could become negative. This could inadvertently lead to negative capacity prices (*i.e.*, cleared resources, if any, would be charged for providing capacity). We believe this would not be a meaningful outcome. Of course, Net CONE could ultimately become *zero*, if continued entry of demand response resources resulted in increased E&AS margins for peaking resources to the point where the need for explicit capacity payments would be eliminated. Under such conditions, points *b* and *c* of the

[114] 2×CONE – E&AS = CONE + (CONE – E&AS) = CONE + NetCONE

[115] 1.5×NetCONE = 1.5×(CONE-E&AS) = 1.5×CONE – 1.5×E&AS

[116] If a = (1.5×CONE–E&AS) and b = NetCONE = (CONE-E&AS), then a-b = 1.5×CONE – CONE = 0.5×CONE

VRR curve and the associated capacity price should be allowed to become (and possibly remain) at zero without obtaining negative values.

- ***Increase the cap of the VRR curve.*** A more robust VRR curve would require a higher cap. We recommend redefining point *a* by setting it equal to point *b* plus at least 0.5×CONE, possibly to 1.0×CONE above point *b* as proposed in the originally-filed VRR Curve developed by Prof. Hobbs.[117] This would prevent the collapse of the VRR curve and outcomes well below reliability targets when the E&AS offset becomes anomalously high. It would also produce a steeper and more stable upward slope between points *a* and *b* compared to the current VRR curve (which defines point *a* as 1.5×NetCONE). The higher cap will also preserve resource adequacy by reducing the risk of deterring offers that may be temporarily above the current cap because the historical E&AS offset differs significant for expected future E&AS margins or due to errors in the Net CONE estimation). As discussed below, probabilistic simulations suggest that increasing point *a* to 0.5×CONE above point *b* would offset approximately 80% of the performance deterioration caused by combining the Settlement Curve with a historical E&AS offset.[118]

If the cap of the VRR curve cannot be increased, the identified performance risks could be addressed through a combination of (1) a floor for point *a* and (2) a limit on maximum annual reductions to Net CONE. Based on our probabilistic simulations, this floor for point "a" would need to be *at least* 0.5×CONE. Based on our probabilistic simulations, this floor would mitigate approximately *half* of the performance deterioration caused by combining the Settlement Curve with a historical E&AS offset. To further increase VRR Curve performance, the floor on point *a* would also need to be combined with cap on year-to-year *reductions* to Net CONE values. This would help reduce the likelihood that the VRR curve is suppressed below the true cost of new entry due to year-to-year fluctuations that do not reflect normalized forward-looking market conditions. To counteract the asymmetric nature of the VRR curve, no limit would apply to annual increases in Net CONE values. As discussed below, the simulation results indicate that the combination of a 0.5×CONE floor for point "a" and the 20% limit on downward annual Net CONE adjustments would also offset approximately 80% of the performance deterioration seen with the current VRR curve under historical offset simulation conditions.

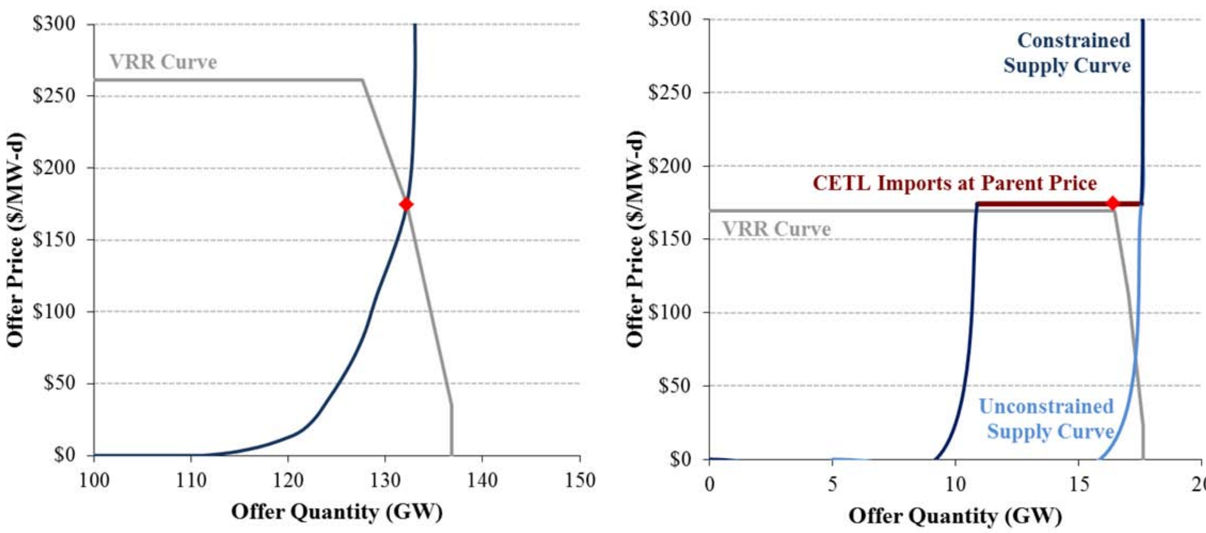
We make the recommendation to increase point *a* of the VRR curve based on two considerations. First, our probabilistic simulations show that this significantly improves VRR curve performance. But second, the resulting difference between points *a* and *b* would, for the most part, also likely be large enough to exceed the range of likely discrepancies differences between *administratively-determined* Net CONE values (*i.e.*, based on administratively-determined CONE and administratively-determined historical E&AS margins) and *true* Net CONE values (*i.e.*, the actual cost of new entry less actual E&AS margins that suppliers forecast for the delivery year).

117 For point b values equal to or greater than zero.

118 Using the current definitions of points "b" and "c" but setting point *a* to 1.5×CONE (i.e., without subtracting any E&AS offset) would eliminate over 90% of the performance deterioration caused by combining the Settlement Curve with a historical E&AS offset. Simulations of the originally-filed VRR curve which defined the cap as 2×CONE minus E&AS show only very modest performance deterioration.

Our recommendation to increase the cap of the VRR curve would also avoid VRR performance risk within LDAs that have already been encountered. For example, in the BRA for the 2010/11 delivery year the E&AS offset in SWMAAC was $130/MW-day while it was only about $30/MW-day for the unconstrained RTO. As shown in Figure 20, the resulting cap for the VRR Curve of SWMAAC was less than Net CONE for the unconstrained RTO. This meant that SWMAAC cleared at a price above its cap, because the LDA did not price separate. More importantly, however, it also means that RPM would not have been able to procure sufficient resources within SWMAAC, had the LDA (including CETL import capability) been resource deficient. Even if resources would have been available within SWMAAC at higher prices above Net CONE for the RTO, they would not have been procured due to the low cap of the VRR curve in SWMAAC.

Figure 20
2010/11 VRR Curves and BRA Results for RTO and SWMAAC



C. PROBABILISTIC SIMULATIONS OF THE VRR CURVE

As part of PJM's analysis of the originally-filed and subsequently settled VRR Curve design, PJM's witness, Professor Benjamin Hobbs, developed a dynamic, agent-based, economic simulation model that conducts probabilistic simulations of generation investments over time in response to price-based incentives in the energy, ancillary service, and capacity markets. The model calculates profits earned by generators in the E&AS markets as a function of actually achieved reserve margin in a particular delivery year. The model assumes that investors will add combustion turbines based on their recent profitability and forecast profits based on their expectations for future demand, capacity prices determined by the shape of the VRR curve, E&AS margins, and the riskiness of their revenue stream. Section IV.C of our 2008 RPM Report contains a more detailed description of the model developed by Professor Hobbs and our updates to it.[119]

[119] For a complete description of the Hobbs model, see Hobbs *et al.* "A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model," *IEEE Transactions on Power Systems*, Vol. 22, NO. 1, February 2007. The simulation analysis was originally presented in the

Continued on next page

We find that the probabilistic simulations are very helpful in analyzing how certain changes in the VRR design may affect RPM performance. It is important to recognize, however, that the simulations are not forecasts of likely outcomes. Actual RPM performance under real-world conditions will necessarily differ, potentially significantly, from the simulations results. To allow for probabilistic simulations, the model is only a stylized representation of RPM and investment behavior and is based on significant simplifications. For example, model simulates only one market area (*i.e.*, the RTO without LDA structure) and only one type of generation technology (*i.e.*, a combustion turbine; without demand response or other type of generation technologies). It also employs a supply curve that is vertical beyond the CT capacity planned on a three-year forward basis (*i.e.*, essentially assumes a hockey-stick shape of the supply curve) without an ability to adjust plans through the means of incremental auctions. Nevertheless, we believe that the simulation results provide a strong indicator of the direction and magnitude of the likely impacts of design elements on RPM performance.

1. Updates to Simulation Parameters

As we did for the purpose of our 2008 RPM Report, we have updated model input parameters to reflect current values for CONE, peak demand, CT dispatch costs, and other input parameters. **Table 19** summarizes the input parameters used in the original simulations by Prof. Hobbs, in our 2008 RPM Report, and the current simulations.

Table 19
Original and Updated Simulation Model Parameters

Parameter		Hobbs 2005 Analysis	2008 Analysis	2011 Analysis
Developer Gross CONE	*($/MW-y ICAP)*	$61,000	$72,000	$112,868
Admnistrative Gross CONE	*($/MW-y ICAP)*	$72,000	$72,000	$112,868
CT Variable Cost	*($/MWh)*	$79	$74	$48
EFORd	*(%)*	7.0%	6.2%	6.2%
Initial Peak Demand	*(MW)*	63,957	144,644	135,080
Load Growth	*(%/y)*	1.7%	1.4%	1.3%

Sources and Notes:
See Hobbs (2005, 2007); Pfeifenberger and Newell, *et al.* (2008), p. 59. Updated developer and administrative gross CONE from PJM (2011q), pp. 2226-7. Updated CT variable cost based on 9,289 btu/kWh heat rate, $4.50/mmbtu gas price, and $6.47/MWh VOM. EFORd from 2010/11 planning parameters, PJM (2008b). Load growth from PJM 2011 load forecast report, PJM (2011g).

Continued from previous page
Affidavit of Prof. Hobbs, filed as Attachment H to PJM's initial RPM application on August 31, 2005 in FERC Docket Nos. ER-05-1410 and ER-05-148. Updated simulations that included the settlement-based VRR Curve were presented in the Supplemental Affidavit of Prof. Hobbs, filed at FERC with the Settlement Agreement on September 29, 2006.

2. Updated Simulation Results Using a Constant E&AS Offset

The simulation results of the originally-filed VRR curve, the Settlement Curve (*i.e.*, the currently applicable VRR curve), and a vertical demand curve (capped at 2×CONE-E&AS) are shown in Table 20. These results are based on 25 simulations of 100 years each for each of the three curves. As shown in the table, the Settlement Curve performs quite well. Based on generator commitments, forecast planning reserves for the delivery year exceed the reliability target during 86% of all years. Average actual reserve margins during the delivery years are 0.74 percentage points above the reliability target with a standard deviation of 5.1 percentage points due to uncertainties such as weather and generation outages.[120] Total consumer payments for capacity and E&AS margins are $142/kW-year with a standard deviation of $47/kW-year. As shown, this level of reliability and costs approaches the performance of the Original VRR curve. In contrast, simulations of the Vertical Demand Curve show much lower performance in terms of reliability (with average reserve margins 2.4 percentage points below the reliability target) and substantially higher average customer costs ($245/kW-year) and pricing uncertainty (a standard deviation of $176/kW-year).[121]

Table 20
Hobbs Simulations with Updated Parameters and Constant E&AS Offset

	Fraction of Time Cleared Resources Exceed Requirement	Realized Reserve Margin minus Target Reserve Margin	Generator Profits after Capital and Operating Cost	Scarcity Revenue (Portion of E&A/S From Scaricity Pricing)	Average Capacity Price	Consumer Payments for Capacity and Scarcity
	(%)	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/peak kW-y)*
Original Hobbs Curve (*a* = 2 x CONE - E&A/S)						
Average	96%	1.18%	9	15	105	140
Standard Deviation		*(5.1%)*	*(31)*	*(27)*	*(13)*	*(42)*
Settlment Curve: Current RPM VRR Curve (*a* = 1.5 x Net CONE)						
Average	86%	0.74%	11	17	105	142
Standard Deviation		*(5.1%)*	*(34)*	*(29)*	*(13)*	*(47)*
Vertical Demand Curve (price cap = 2 x CONE - E&AS)						
Average	27%	-2.44%	94	47	157	245
Standard Deviation		*(6.2%)*	*(132)*	*(64)*	*(95)*	*(176)*

Sources and Notes:
Each simulation involves 100 runs through 100 years each.
Reported numbers represent the average of run averages and the average of run standard deviations.
Generator profit, revenue, and capacity price reported on a UCAP basis; consumer payments normalized by peak load.

3. Updated Simulation Results Using a 3-Year Historical E&AS Offset

As noted, the results shown in Table 20 above are based on simulations holding the E&AS offset constant over time. (This is consistent with an approach in which the E&AS offset would be

120 As noted above, the reliability target is one percentage point below the anchor point (point "b") of the VRR curve.

121 As we noted on page 66 of our 2008 RPM Report, these simulations overstate the level of costs and uncertainty associated with a vertical demand curve. However, the vertical demand curve resulted in modestly higher costs and uncertainty even under more conservative alternative modeling assumptions.

estimated based on equilibrium market conditions, as discussed in Section IV.B.) Table 21 shows simulations results for an E&AS offset based on the 3-year average of the simulated historical E&AS margins.

As Table 21 shows, simulated RPM performance of the Settlement Curve drops *substantially* when the constant E&AS offset is replaced with a historical E&AS offset. Most notably, forecast 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 percentage points *below* the reliability target (down from 0.7 percentage points *above*). Total consumer payments for capacity and E&AS margins increase to $207/kW-year (up from $142/kW-year) with a standard deviation of $146/kW-year (up from $47/kW-year). Table 21 shows, however, the use of historical E&AS offsets deteriorates performance only modestly for the originally-filed VRR curve.

Table 21
Hobbs Simulations with Updated Parameters and Historical 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)*

Sources and Notes:
Each simulation involves 100 runs through 100 years each.
Reported numbers represent the average of run averages and the average of run standard deviations.
Generator profit, revenue, and capacity price reported on a UCAP basis; consumer payments normalized by peak load.

These marked performance deteriorations observed in the Hobbs model simulations with historical E&AS offsets were already noted in our 2008 RPM Report, which explained:

> …the use of historical E&AS averages can create "resonances" in the simulations that can lead to unstable results. For instance, in an extreme weather year, E&AS margins could be very high. As a result, even after averaging over three historical years, the resulting value for Net CONE could be very low. As a result of the low Net CONE value, however, little or no entry occurs in the model. Because of this lack of entry, reserve margins decline further, which may increase E&AS margins to the point at which Net CONE is zero or even negative. At that point, entry is mostly a function of high but very volatile energy and ancillary service revenues. At other times, however, load fluctuations may artificially depress the E&AS margins, at which point Net CONE may return to meaningful values for some period of time. This dynamic leads to highly unstable simulations with high average costs and high volatility. Even utilizing longer-term averages of historical E&AS margins and imposing limits on realized E&AS margins did not alleviate the problem in the simulations. Whether such instabilities would be very likely under real-world conditions is unclear, but these simulation results nevertheless highlight the risk of relying on outdated E&AS margins that are not consistent with investors' anticipated market conditions.[122]

We have analyzed these simulation results in more detail and found that the primary reason for the poor performance of the Settlement Curve using historical E&AS offsets relates to how point *a* (the cap of the VRR curve) is defined. As discussed qualitatively in the previous subsection, the simulations frequently get "stuck" at points well below the reliability target when the VRR curve collapses due to historical E&AS margins that are equal to or exceed CONE—until load or generation outage fluctuations depress the E&AS margins below CONE, at which point the VRR curve re-emerges and its slope returns the system to the reliability target.

Table 21 also summarizes the simulation results of four alternative definitions for points *a* of the Settlement Curve, including simulations that limit the extent to which Net CONE values can decrease from one year to the next. Points *b* and *c* remain unchanged at 1.0×NetCONE and 0.2×Net CONE, but are limited to values greater or equal to zero (as is assumed in the simulations of the Settlement Curve).

Alternative 1 simply adds a floor of 0.5×CONE to point *a*, which becomes active only if the 3-year average historical E&AS offset exceeds ⅔×CONE. As the simulation results show, this design change increases average achieved reserve margins by almost 3 percentage points (from negative 5.18 to negative 2.24 percentage points below the reliability target), mitigating approximately half of the performance deterioration caused by the historical E&AS offset.

Alternative 2 adds a 20% limit on annual *decreases* of Net CONE to Alternative 1 (which imposed a 0.5×CONE floor for point "a" of the Settlement Curve). This combination mitigates over 80% of the performance deterioration and achieves an average reserve margin that is only 0.4 percentage points below the reliability requirement. Total customer costs are reduced to \$151/kW-year (down from \$207/kW-year) and volatility is reduced to a standard deviation of

[122] 2008 RPM Report page 61-62 (footnote omitted).

customer costs of $72/kW-year (down from $146/kW-year). While average outcomes are still slightly below the reliability target, the performance of this combination is similar to the originally-filed VRR curve, which had a much higher cap (2×CONE less E&AS) and a flatter bottom half of the curve. We have also evaluated limiting both annual increases and decreases of Net CONE values, but found that such a symmetric limit does not improve the identified VRR Curve performance risks that are created by the asymmetric nature of the curve.

Alternative 3 defines point *a* to as "point *b* plus 0.5×CONE," which is also equal to "Net CONE plus 0.5 CONE" or "1.5×CONE minus E&AS" (with a floor of zero). This definition yields a higher cap than the current cap of the VRR curve (1.5×CONE minus 1.5×E&AS), which also results in a slightly steeper and stable upward slope between points *a* and *b*. The simulations results show that this change increases average achieved reserve margins by almost 5 percentage points to an average that is only 0.5 percentage points below the reliability target, mitigating approximately half of the performance deterioration caused by the historical E&AS offset. Customer costs and volatility are similar to the simulation results for Alternative 2.

Finally, Alternative 4 defines point *a* as 1.5×CONE without subtracting any E&AS offset. This achieves a simulated average reserve margin that is 0.26 percentage points above the reliability requirement with customer costs of $149/kW-year and a volatility of $67/kW-year. This level of simulated performance is close to the performance of the Settlement Curve with a constant E&AS offset as shown earlier in Table 19.

The simulations of these alternatives show that point a, the cap of the VRR curve, would need to be approximately 1.0×CONE above point *b* (*i.e.*, as proposed in the original Hobbs curve) to yield an average reserve margin that is above the IRM target.

We believe these simulations will accurately capture the nature of the discussed performance risks, even though the simulations will likely overstate volatility associated with the use of historical E&AS margins due to the hockey-stick nature of the modeled supply curve and the absence of adjustments to resource procurement through incremental auctions. However, the simulations are likely to understate actual RPM uncertainties related to capacity prices and resource adequacy within LDAs.

4. Updated Simulation Results Using a Normalized 3-Year Forward-Looking E&AS Offset

As noted in our 2008 RPM Report, we also simulated an E&AS offset that is consistent with *anticipated* (*i.e.*, normalized forward-looking rather than historical) market conditions.[123] Using this normalized forward-looking E&AS offset performed markedly better than the highly unstable simulations based on historical averages of actual E&AS margins. The results from our updated simulations in Table 22 below show that determining Net CONE based on the projected normalized E&AS margins performs slightly better than the simulations undertaken by Prof.

[123] These simulations are based on the average of projected (normalized) E&AS margins for the three years leading up to the delivery year, taking into account the capacity commitment already known for these years. Determination of these 3-year forward looking E&AS margins is possible in the simulations because achieved reserve margins (relative to forecast peak load) is already known through the previous BRA results and the model determines E&AS profits as a simple function of projected reserve margins.

Hobbs using a fixed E&AS offset to determine Net CONE. More specifically, relying on projected E&AS margins—and assuming accurate projections of normalized future E&AS margins—offers improvements over the updated Hobbs simulations based on fixed E&AS revenues (Table 20 above) in terms of costs, price volatility (as measured by standard deviations), and reliability.

Table 22
Hobbs Simulations with Normalized Forward-Looking E&AS Offset

	Fraction of Time Cleared Resources Exceed Requirement	Realized Reserve Margin minus Target Reserve Margin	Generator Profits after Capital and Operating Cost	Scarcity Revenue (Portion of E&A/S From Scaricity Pricing)	Average Capacity Price	Consumer Payments for Capacity and Scarcity
	(%)	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/peak kW-y)*
Original Hobbs Curve (a = 2 x CONE - E&A/S)						
Average	97%	1.15%	9	16	104	141
Standard Deviation		(5.2%)	(31)	(28)	(11)	(42)
Settlment Curve: Current RPM VRR Curve (a = 1.5 x Net CONE)						
Average	90%	0.83%	10	16	105	141
Standard Deviation		*(5.1%)*	*(32)*	*(29)*	*(11)*	*(45)*

Sources and Notes:
Each simulation involves 100 runs through 100 years each.
Reported numbers represent the average of run averages and the average of run standard deviations.
Generator profit, revenue, and capacity price reported on a UCAP basis; consumer payments normalized by peak load.

D. The Slope of the VRR Curve

In this section we examine the slope of the VRR curve and its impacts on RPM price volatility based on a scenario analysis of the first eight base auctions undertaken to date. This analysis indicates that the slope of the VRR curve has reduced the price volatility that would have been experienced if RPM employed a vertical demand curve. However, the reductions in price volatility are smaller than we might have expected. In response to some stakeholder comments, we have also tested the extent to which VRR curve with a lower slope would have further reduced price volatility. Making the VRR curve flatter does not appear to have a large enough impact in price stability to be a desirable design change given the additional quantity uncertainty that would be introduced.

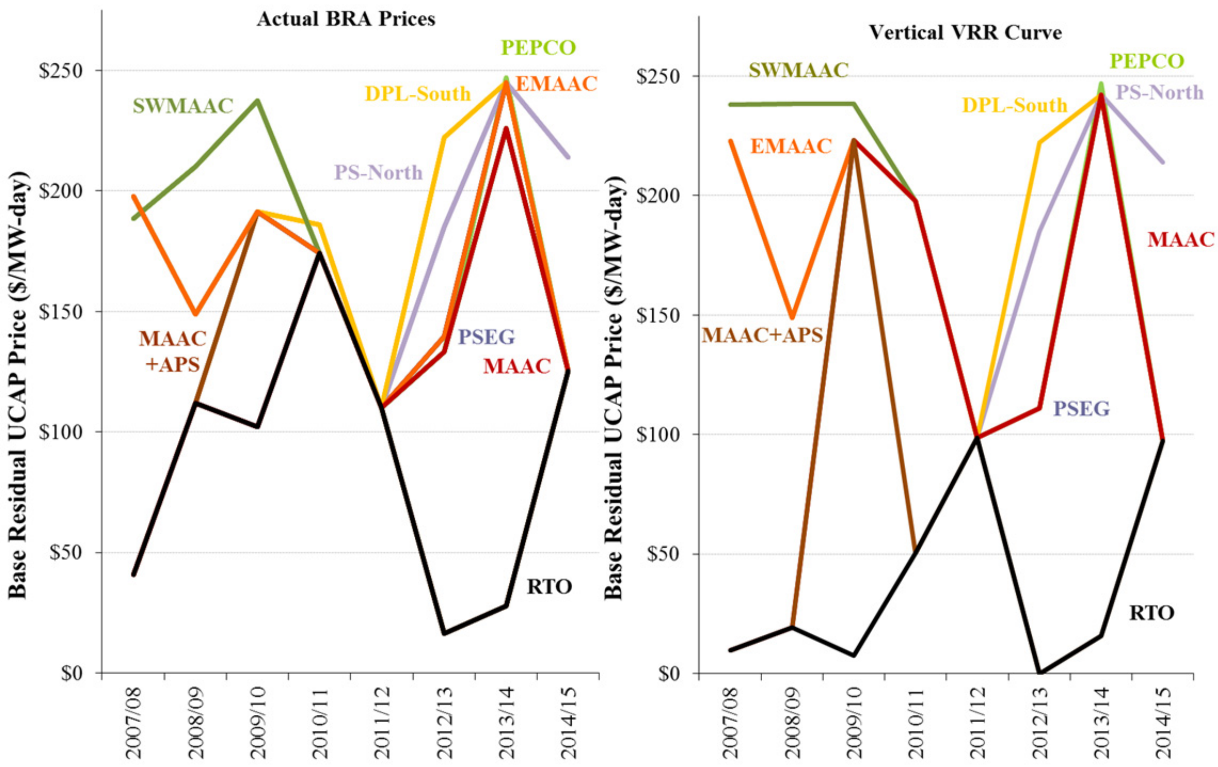
We also examined, and ultimately rejected, the idea that more gradual VRR curve slope could be a valuable design change to reduce price uncertainty in small LDAs. While such a change could potentially produce more price stability in small LDAs, we find that it would reduce the incentive to develop incremental capacity in these locations.

1. VRR Curve Slope in the RTO and LDAs

As discussed in our 2008 RPM report and confirmed by our updated probabilistic simulations, the sloped VRR curve results in lower average costs and lower uncertainty than a vertical demand curve. In addition, a sloped VRR curve: (1) helps mitigate the potential exercise of market power by reducing the incentive for suppliers to withhold capacity when aggregate supply is near the target reserve margin; and (2) recognizes that capacity above the target reserve margin provides some incremental reliability benefits, although at a declining rate.[124]

We were able to explore the extent of price risk mitigation due to the sloped VRR curve based on a scenario analysis of results from the first eight base auctions. Figure 21 shows the results of this scenario analysis, which re-simulates prices of previous BRAs assuming that, but for the VRR curve slope, all other historical auction parameters and supply curves would have remained unchanged. We also recognize, however, that assuming identical historical supply curves is not a realistic assumption, as different supplier expectations would have driven different bidding behaviors and different clearing results would have affected subsequent auctions. For these reasons, we consider these scenario analyses to be helpful indicators of the impacts of the VRR curve slope but recognize that they must be interpreted with caution.

Figure 21
Actual BRA Prices (left) and Prices with a Vertical VRR Curve (right)



Notes:
Left chart shows actual BRA prices.
Right chart shows a scenario analysis of historical BRA prices if the VRR curve had been vertical at point *b*.

The left chart of Figure 21 shows actual BRA auction prices while the right chart shows prices that would have been realized with a vertical VRR curve. The comparison of these two charts shows that the volatility with the actual VRR curve is somewhat lower than under a vertical curve. For example, actual MAAC prices between 2008/09 and 2009/10 increased by $79/MW-day, while the price increase for the vertical VRR curve simulation was $204/MW day,

124 The value of these incremental reliability benefits do not necessarily reflect the value implied by the VRR curve however, since the VRR curve is not tied to any such calculations.

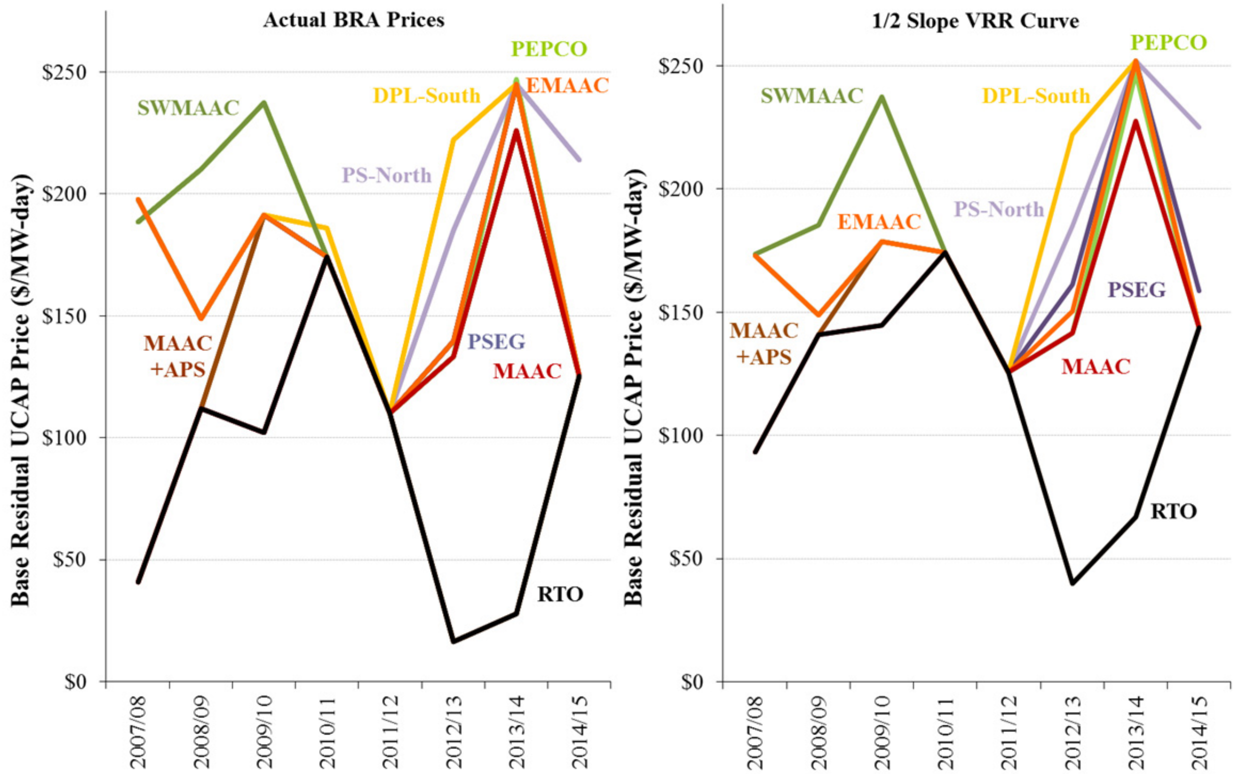
or more than 2.5 times larger. However, overall, the reduction in price volatility due to the VRR curve slope is somewhat less than we would have expected. The more moderate impact is not as surprising, however, when considering the causes of price changes we have identified and discussed in Sections II. It appears that the slope of the VRR curve, while beneficial in reducing price volatility, has not been sufficiently flat to fundamentally reduce the impacts of other uncertainty factors, such as changes in CETL values or whether individual LDAs are modeled.

Members of the generation owner, transmission owner, and other supplier sectors stated in our interviews that the VRR curve is too steep and, as a result, yields high price uncertainty. However, members of the end use customer sector and some state commissioners regulating FRR entities have placed substantial emphasis on the quantity uncertainty that the sloped VRR curve is creating. In response to these stakeholder comments, we also assess the extent to which a flatter VRR curve could reduce price uncertainty.

Figure 22 shows actual BRA prices (left chart) compared to simulation results under a more gradual VRR curve with half the slope of the existing curve (right chart). The simulations show that some additional reductions in price volatility could have been achieved under a more gradual VRR slope. For example, actual MAAC prices between 2011/12 and 2012/13 decreased by $79/MW-day, while under the price decrease using a more gradual VRR curve was reduced to $38/MW-day or less than half. Other LDAs, however, would have seen little benefits from a flatter VRR curve. The simulations indicates that while a more gradual VRR curve would somewhat reduce price volatility in RPM, the impact would only be modest.

Given these results and our analysis of the drivers behind BRA price changes presented in Section II, we conclude that it will be more beneficial to pursue other available options to reduce price volatility in RPM. As discussed, some of the factors that have driven price volatility are related to previous design issues that have since been corrected, including problems with not modeling LDAs that would have price separated and the exclusion of large amount of ILR supplies in the first five auctions. Other drivers of uncertainty include uncertainty and volatility in administratively-determined parameters, such as the load forecast and CETL and the potential for not modeling LDAs that may price separate in the future. We examine the potential for reducing price volatility introduced by these factors further in Section VI.

Figure 22
Actual BRA Prices (left) and Prices with a Gradual VRR Curve (right)



Sources and Notes:
Left chart shows actual BRA prices.
Right chart shows a scenario analysis under a VRR curve with ½ the slope of the actual historical curve.

2. Reduced VRR Curve Slope in Small LDAs

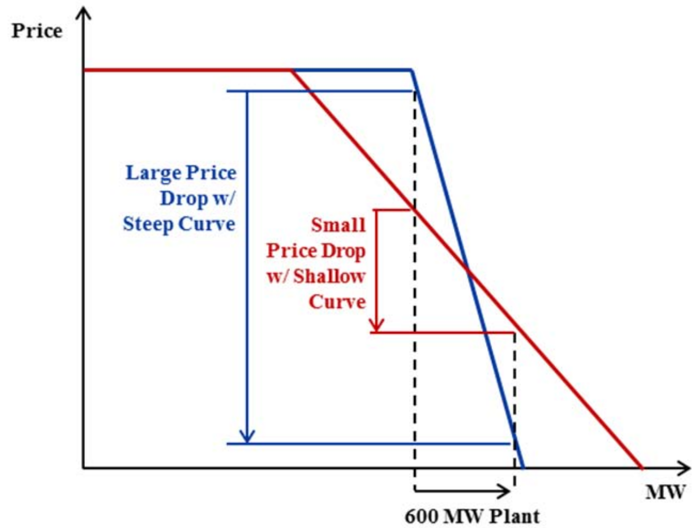
While it appears that a more gradual slope in the RTO overall may not be the most beneficial approach to reducing price volatility, we considered whether it may be beneficial in the smallest LDAs. This approach is used in New York, which has relatively more gradual VRR curve slopes in the smaller capacity zones covering New York City and Long Island than in the greater NYISO region.

It makes intuitive sense that a flatter slope would provide more stability in small LDAs. It might also help mitigate the impacts of individual generating plants, which could substantially reduce capacity prices in small LDAs for many years. In SWMAAC or PSEG for example, the impact of a single 600 MW plant corresponds to a price difference between zero and Net CONE along the VRR curve. In even smaller LDAs such as DPL-South, PSEG-North and PEPCO, the impact of a 600 MW plant would be the difference between the price cap and the price floor.[125] Figure 23 shows schematically how the addition of one large plant can substantially reduce prices, while under a more gradual VRR curve slope the price impact of a single large plant would be less.

[125] See the quantity difference between points a, *b*, and *c* in the 2014/15 BRA planning parameters, PJM (2011b).

This indicates that in a stand-alone small system, a more gradual VRR slope would mitigate such large price impacts. However, the implications of such a change are more nuanced in a multi-area capacity market such as RPM.

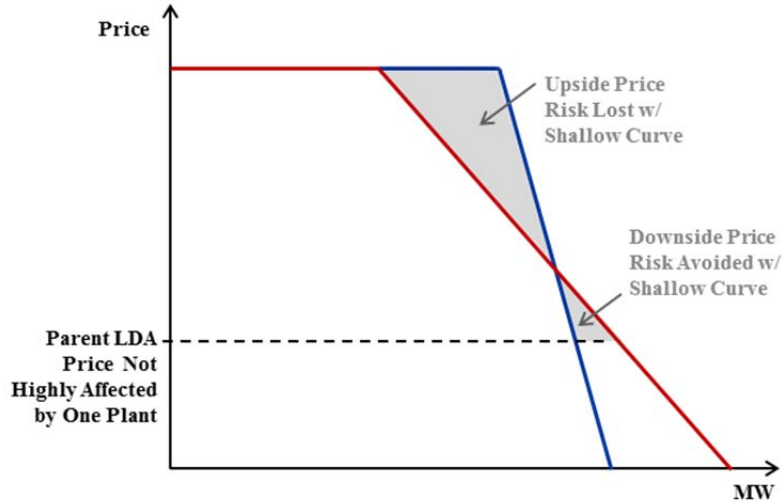
Figure 23
Price Impact of a 600 MW Plant with VRR Curves of Different Slopes
(In a Small Stand-Alone LDA *without* a Parent LDA)



In a market with a nested LDA structure like PJM, price impacts in small LDAs cannot be examined in isolation from prices in their larger parent LDA or unconstrained RTO. As depicted in Figure 24, price impacts in small LDAs are limited on the low end by the prices of their parent LDA. That is, the price of a small LDA cannot drop below the price of the parent LDA. For this reason, the downside price impact of a large plant addition in a small LDA is already limited, because the larger parent LDA price will not be substantially impacted by the addition of a single plant. The remaining avoided downside price risk is shown as the small shaded triangle in Figure 24. The figure also shows that the "upside price risk" that would be lost by applying a flatter VRR curve to small LDA would be much larger than the downside price risk mitigation, as shown in the larger shaded triangle.

The upside price risk lost under such a change is much larger than the downside price risk gained unless the parent LDA price is much lower than the small LDA price. In fact, as a result of this asymmetry, reducing the slope of the VRR curve in small LDAs would reduce the amount of capacity procured at high prices and, thus, also reduce incentives to add resources to the LDA.

Figure 24
Upside and Downside Price Risk Impact of a Shallow VRR curve
(In a Small LDA *with* a Parent LDA)



E. *SUMMARY OF* VRR CURVE RECOMMENDATIONS

As discussed above, we recommend that PJM and its stakeholders consider and more fully evaluate the following recommendations regarding the slope, cap, and forward period of the VRR curve design.

1. ***Increase the Cap of the VRR Curve to Improve Performance*** — we recommend that PJM and its stakeholders consider raising point *a* equal to point *b* plus 0.5×CONE, which would result in a higher cap and a steeper and more stable upward slope between points *a* and *b* compared to the current VRR curve. It should also be clarified that the value of Net CONE (for purpose of defining points a, b and c of the VRR curve) cannot be less than zero.
2. ***Otherwise maintain the Slope of VRR Curve***, including within LDAs.
    a. *VRR Curve for Unconstrained RTO* — We recommend maintaining the VRR curve at its current value (other than the modest change in slope between points *a* and *b*, due to the increase cap of the VRR curve). The current slope has reduced the price volatility relative to a vertical curve. An even more gradual slope would not result in significant further reduction in price volatility, but would create greater uncertainty in procured quantity relative to the reliability target.
    b. *VRR Curve in Small LDAs* — We recommend keeping the current slopes of the VRR curves the same even within small LDAs. Imposing a more gradual slope in constrained LDAs would reduce upside price risk without substantially impacting downside price risk (unless the parent LDA price were substantially lower), thereby reducing investment incentives.

VI. ANALYSIS OF MARKET DESIGN ELEMENTS

Our analysis of individual market design elements addresses six groups of design elements and administratively-determined RPM parameters. First, we analyze transmission-related factors and opportunities to reduce their impact on RPM price uncertainty. Second, we offer recommendations to improve the transparency of load forecasts and the load forecasting process. Third, we discuss the comparability of DR and generating resources and associated DR performance concerns. Fourth, we address the desirability and design of the 2.5% short-term resource procurement target. Fifth, we discuss concerns related to market monitoring and mitigation. And, finally, we explore options for expanding the NEPA or facilitating long-term procurement.

A. TRANSMISSION-RELATED FACTORS

This section assesses how transmission-related factors affect RPM and identifies opportunities to reduce their effects on the uncertainty and volatility of RPM prices—while still accurately representing transmission limits, maintaining reliability, and providing accurate price signals. We examine options for: (1) making the CETL parameter more transparent, more predictable, and less volatile in order to reduce volatility and improve the predictability of auction clearing prices in LDAs; (2) improving how transmission constraints are represented in RPM auctions; (3) reducing the need for RMR contracts that address transmission constraints into LDAs; and (4) improving coordination between the transmission planning process and RPM.

1. Transparency and Stability of the Capacity Emergency Transfer Limit

The capacity emergency transfer limit (CETL) parameter expresses the first contingency total transfer capability into each LDA.[126] The capacity emergency transfer objective (CETO) is the transfer capability into the LDA that would be required to maintain a 1-event-in-25-year conditional loss of load expectation for the LDA, assuming perfect availability of such transmission capability and resources outside the LDA.[127] These parameters are used for several purposes: (1) to determine whether to plan transmission enhancements to maintain reliability (*i.e.*, when CETL < CETO); (2) to determine whether to model an LDA in the RPM auctions (*i.e.*, when CETL < 1.15 × CETO); and, most relevant to this discussion, (3) to set the import limits into an LDA as modeled in the RPM auctions.[128]

The CETL parameter determines how much lower-cost capacity an LDA may import from outside while still observing transmission constraints. Because CETL can be large relative to the size of an LDA and the slope of the LDA's VRR curve, its value can have a major effect on auction prices. As discussed in Section II, CETL changes have been a major contributor to the observed volatility and unpredictability of auction prices. This is because CETL can change

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126 See PJM (2011i), pp. 53-54.

127 Section III.G contains additional discussion of the 1-in-25 reliability standard for LDAs. See PJM (2011i), pp. 53-54.

128 See PJM (2011i), pp. 27-28 and Attachment C; PJM (2011d), pp. 10-13.

significantly from one auction to the next due to planned transmission upgrades, deferrals of planned upgrades, generation plant retirements, or shifts in the load distribution within an LDA.

We first document changes in historical CETL values, including how and why they have changed over time. We then examine options that could make CETL determination more transparent, more predictable, and more stable.

a. Historical Changes in CETL and Their Effects on RPM Auctions

Table 23 lists the CETL values that applied to the various LDAs in each of the past base residual auctions as well as the 2012/13 incremental auctions.[129] The year-to-year changes in CETL have been substantial and in many years the magnitude of increases or decreases has been comparable to the addition or retirement of several large generating plants. Table 23 shows, for example, that the 2013/14 CETL for MAAC and EMAAC decreased by almost 2,000 MW, or more than the impact of three large CC plants. As discussed in Section II, these CETL reductions were a major contributor to LDA prices in 2013/14 that were higher than in the previous or subsequent BRA.

The following year, in 2014/15, CETL values reverted close to their levels two years earlier when the MAAC and EMAAC CETLs were more than 1,000 MW higher. These CETL increases were a major contributor to LDA price reductions in the 2014/15 auction. These impacts are larger in the small LDAs, including PEPCO, which experienced a CETL increase of 12.5% of the reliability requirement between the 2013/14 and 2014/15 BRAs, equivalent to almost twice the width of the sloped portion of the VRR curve.[130]

b. Causes of CETL Uncertainty

Table 23 shows that CETL values have changed substantially over time, which contributed to significant changes in auction prices, as discussed in Section II. The specific causes of the largest CETL changes are summarized in Table 24. Some of the largest CETL changes were due to major planned transmission projects and the subsequent modification of the projects' online dates. For example, the Susquehanna-Roseland backbone transmission project was planned to be in service starting with the 2012/13 delivery year, but the project has been substantially delayed due to environmental permitting difficulties.[131] The transmission line is now expected to be online starting in 2015/16.[132] When Susquehanna-Roseland was first modeled in RPM, it coincided with a relatively small CETL increase of 275 MW in EMAAC; when it was subsequently delayed, it caused a CETL reduction of 1,455 MW between the 2012/13 BRA and the first incremental auction for that delivery year, or a drop of 1,984 MW between the BRAs for the 2012/13 and 2013/14 delivery years.

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[129] Prior to 2012/13, CETL values were not updated in the incremental auctions, see PJM (2011d), p. 60.

[130] The quantity difference between points a and c on the VRR curve for PEPCO in 2014/15 was 621 MW, while the change in CETL between 2013/14 and 2014/15 was 1,123 MW or 1.8 times higher. See PJM (2010a, 2011b).

[131] See PJM (2011l).

[132] *Id.*

Table 23
Historical CETL Values and Changes

Year	MAAC+APS	MAAC	EMAAC	SWMAAC	PSEG	DPL-S	PS-N	PEPCO
Capacity Emergency Transfer Limit (MW)								
2007/08	--	--	5,845	5,699	--	--	--	--
2008/09	--	--	7,930	5,610	--	--	--	--
2009/10	4,941	--	8,505	6,391	--	--	--	--
2010/11	--	6,645	--	6,667	--	1,447	--	--
2011/12	--	--	8,804	--	--	1,857	--	--
2012/13	--	6,377	9,079	7,400	6,290	1,746	2,755	--
1st IA	--	*6,377*	*7,624*	*7,400*	*6,077*	*1,746*	*2,675*	--
2nd IA	--	*6,098*	*7,624*	*6,950*	*6,077*	*1,746*	*2,675*	--
2013/14	--	4,460	7,095	6,725	5,868	2,123	2,570	4,483
2014/15	--	5,694	8,189	7,719	5,721	1,925	2,372	5,606
CETL Change from Previous BRA (MW)								
2008/09	--	--	2,085	(89)	--	--	--	--
2009/10	--	--	575	781	--	--	--	--
2010/11	--	--	--	276	--	--	--	--
2011/12	--	--	299	--	--	410	--	--
2012/13	--	(268)	275	733	--	(111)	--	--
1st IA	--	*0*	*(1,455)*	*0*	*(213)*	*0*	*(80)*	--
2nd IA	--	*(279)*	*(1,455)*	*(450)*	*(213)*	*0*	*(80)*	--
2013/14	--	(1,917)	(1,984)	(675)	(422)	377	(185)	--
2014/15	--	1,234	1,094	994	(148)	(198)	(198)	1,123
CETL Change as Percent of LDA Reliability Requirement								
2008/09	--	--	5.5%	-0.5%	--	--	--	--
2009/10	--	--	1.5%	4.7%	--	--	--	--
2010/11	--	--	--	1.6%	--	--	--	--
2011/12	--	--	0.7%	--	--	13.0%	--	--
2012/13	--	-0.4%	0.7%	4.3%	--	-3.7%	--	--
1st IA	--	0.0%	-3.7%	0.0%	-1.6%	0.0%	-1.3%	--
2nd IA	--	-0.4%	-3.8%	-2.7%	-1.7%	0.0%	-1.3%	--
2013/14	--	-2.6%	-4.9%	-3.8%	-3.1%	12.6%	-2.9%	--
2014/15	--	1.7%	2.7%	5.7%	-1.1%	-6.6%	-3.2%	12.5%

Sources and Notes:

BRA and IA parameters, see PJM (2007a, 2009b-d, 2010a, 2010h, 2011b, and 2011j).

2011/12 CETL was calculated for EMAAC and DPL-S although those LDAs were not modeled in RPM.

Prior to 2012/13, CETL was not updated between incremental auctions; see PJM (2011d), p. 60.

Table 24
Summary of Major CETL Changes and Their Causes

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 PSEG-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.

Sources and Notes:
BRA and IA parameters, see PJM (2007a, 2009b-d, 2010a,h, 2011b,j).
Causes of CETL changes from planning parameters reports and communication with PJM staff, PJM (2010i, 2011k).

Other large changes to CETL have not been related to major backbone transmission upgrades but have, instead, been related to smaller transmission projects or modeling changes. In 2014/15, the 1,000 MW CETL increases into MAAC, SWMAAC and PEPCO was caused by adding a new substation and transformer, illustrating the sensitivity of CETL values to even relatively modest transmission projects. Similarly, the 1,917 MW decrease in MAAC and the 675 MW decrease in SWMAAC for 2013/14, and the 1,095 MW increase in EMAAC for 2014/15 demonstrate the considerable sensitivity of CETL to changes in the distribution of load and generation within LDAs.

c. Impacts on and Perceptions of Market Participants

Many of these substantial CETL changes —and their impacts on market prices —came largely as a surprise to market participants when they were published shortly before each auction. The unexpected and unpredictable nature of such sizeable changes has reduced market confidence in the stability of RPM pricing. We attribute the uncertainty that market participants experienced to three causes:

- *CETL Impacts on Market Fundamentals* — In some cases, changes in market prices were caused by underlying market fundamentals and need to be reflected in market prices to achieve efficient outcomes. This is also the case for CETL increases caused by major transmission upgrades, or even large CETL decreases associated with the delay of the Susquehanna-Roseland transmission line.

- *Lack of CETL Forward View and Modeling Transparency* — Market participants lack visibility into CETL determination and CETL's likely future values. This lack of visibility relates to: (a) insufficient information about how CETL will change under changes to market fundamentals including load, supply, and transmission changes; and (b) lack of transparency around how easily constraining transmission elements could be relieved and the benefit from relieving binding constraints.
- *Modeling Sensitivity* — CETL determinations appear to be very sensitive to modeling inputs, including potentially large impacts from small transmission upgrades and small modeling changes regarding the distribution of peak loads and of capacity resources online.

CETL changes that are driven by market fundamentals need to be reflected in market prices, even if they may adversely affect unhedged suppliers or loads. However, changes and uncertainties that are driven by the lack of transparency or modeling sensitivity may have a detrimental effect on the market confidence and should be mitigated, if possible.

d. Recommendations

In response to these concerns, our recommendation is that PJM and stakeholders investigate options to increase CETL transparency and stability. However, we understand that this is not an easy task for a number of reasons. The modeling used to estimate CETL is complex, time intensive, and necessarily involves many data sources and judgments. Further, any changes to CETL determinations must also consider the impacts on the transmission planning process, which uses CETL to identify reliability-related transmission upgrades.

Because we understand that there will not be an "easy fix," we present our recommendation as a single broad objective: to *increase CETL transparency and stability*. We also offer a list of five options that may be explored for achieving that objective. At a high level, the options we present for increasing transparency involve increasing transparency into CETL calculations, its determinants, and expected future changes to CETL. The options we present for increasing CETL stability involve preventing CETL from being limited by easily-solved constraints and avoiding excessive changes to transmission plans.

Options to Increase CETL Transparency: Increasing transparency into CETL determinations and likely future CETL values could reduce unpredictability (without necessarily reducing variability) and avoid surprises just prior to RPM auctions. First, it is important to improve stakeholders' understanding of CETL calculations, CETL determinants, and expected future CETL changes. Sharing CETL load flow cases, calculations, and lists of limiting elements with transmission owners and other market participants could also provide opportunities for stakeholder feedback and sometimes remedial action, as discussed further below. To those ends, we recommend that PJM and stakeholders consider the following:

- ***Provide CETL Forecasts —*** We recommend that PJM consider providing CETL forecasts consistent with RTEP planning studies. The CETL values used for RPM are currently determined by PJM's transmission planning group each January, four months before each base residual auction. Stakeholders would benefit from seeing indicative forward-looking CETL estimates for each modeled LDA that account for planned transmission enhancements and other changes in system conditions. PJM could provide such estimates based on the transmission planning studies it already produces, including the 10-year outlook, 5-year outlook, and the 4-year "retool" study published 3 to 6 months before the BRA parameters are finalized each January. We recommend that PJM quantify CETL values for each of the LDAs modeled in RPM auctions (including, if known, future newly-constrained LDAs) for each of these transmission planning cases to provide market participants with preliminary 4, 5 and 10 year outlooks. If practical, PJM could also provide, for example, sensitivity analyses showing the effects on CETL of removing at-risk generators.

- ***Make Models Available —*** We recommend that PJM consider making the modeling cases and other data and assumptions related to CETL calculations available to market participants. Providing this information would enable market participants to conduct their own sensitivity analyses to understand how CETL might change. Our understanding is that PJM would be authorized to release the model and associated data to market participants that have CEII clearance, consistent with current practice for sharing transmission planning power flow cases. The only data that could not be shared would be the unit-specific EFORd data used in PJM's analysis.

Options to Increase CETL Stability: Although CETL must change when new transmission is planned and other system conditions change, it should be possible to increase the stability of the parameter. One area for improvement is to prevent easily-resolved constraints from limiting CETL. Allowing easily-resolved constraints to limit CETL is inefficient if a low-cost upgrade could substantially increase CETL, and it makes CETL unstable because an upgrade could be made at any time. Another area for improvement is to avoid excessive changes to transmission plans. PJM might be able to address these sources of instability through the following options:

- ***Identify Successive Limiting Elements —*** PJM should consider identifying successive limiting elements and the CETL impacts of relieving those constraints. Along with its release of CETL determinations, PJM already indicates which transmission facilities are the limiting elements. PJM could provide additional analysis to indicate how much CETL would increase if that constraint were relieved, and what the next limiting element would be, and repeat that process for several successive limiting elements. This would provide insight into CETL stability and help market participants identify cost-effective transmission upgrades.

- ***Facilitate Cost-Effective Upgrades —*** PJM could consider facilitating opportunities for cost-effective transmission upgrades through RTEP and market-based responses. Providing the information described above with the 5-year transmission plan and 4-year update would allow market participants to identify cost-effective transmission upgrades. These upgrades could be made either through the RTEP process or through market-based Qualified Transmission Upgrades ("QTUs") and Customer-Funded Upgrades.[133] If easily-solved constraints were upgraded through RTEP or through QTUs or Customer-Funded Upgrades, it would stabilize CETL and prevent it from being inefficiently limited by easily-resolved constraints.

[133] Customer-Funded Upgrades receive Incremental Capacity Transfer Rights ("ICTRs"). We have not specifically examined the effectiveness of the QTU mechanisms.

- ***Develop RTEP Deadband —*** We recommend that PJM and stakeholders consider creating a "deadband" within which transmission plans would not change, as the Regional Planning Process Task Force (RPPTF) has already been discussing.[134] This concept is discussed in greater detail below.

One of the current criteria for reliability planning is to add transmission when the resource adequacy requirement cannot be met by projected generation (ignoring potential new entry) and existing transmission alone. When this condition is expected, CETO (the transmission "objective") will exceed CETL (the transmission limit), which triggers planning for transmission upgrades to address the deficiency. However, if load forecasts or other system conditions subsequently change and CETO drops below available CETL, PJM will delay or cancel the planned transmission upgrades.

This response to short-term changes in system conditions imposes substantial uncertainties by delaying projects in the midst of permitting and other development efforts. The resulting impacts on market participants can be large, as shown by the delay of the Potomac-Appalachian Transmission Highline ("PATH"), which was previously planned to come into service by June, 2015, but was delayed in February for an indeterminate period.[135] The line would likely have increased CETL into MAAC by approximately 2,700 MW.[136]

Our understanding is that the primary reason that PATH was delayed was a substantial decrease in load forecasts related to the economic downturn, but it is not clear for how long the need for the project will be delayed. Such uncertainty in the online date of new transmission projects will also create substantial uncertainty for potential generation developers that will be unwilling to invest in projects that may or may not be needed depending on when and whether a transmission upgrade will come into service.

PJM could reduce this uncertainty by creating a "deadband" within which transmission plans would not change.[137] Basing transmission plans on the current strict threshold of CETO/CETL > 1.0 is problematic because it allows small changes to the load forecast, CETL, or projected installed generation make the difference between a major transmission project being needed in one year but not needed the next. The CETO/CETL ratio of 1.0 also means that these major projects are planned in RTEP as soon as there is a 50% likelihood that the project will be needed based on the current load forecast. To introduce more stability in the planning process, PJM could wait to plan a project until the CETO/CETL ratio exceeds, for example, 1.02 (instead of 1.0), or until the load forecast indicates a 60% likelihood that the project will be needed. Once an enhancement is planned, PJM could adhere to the plan even if the ratio subsequently drops slightly below the current trigger point, for example, until the ratio drops below 0.95, or until the load forecast indicates only a 25% chance that the project will be needed.

[134] See PJM (2011o), p. 9.

[135] See PJM (2011m, 2011n).

[136] Based on the difference in MAAC CETL between Scenario 19 (which did not include the PATH upgrade) and Scenario 20 (which did include the PATH upgrade) in the PJM 2013/14 price scenario analysis. See PJM (2010j)

[137] See PJM (2011o), p. 9.

Such a deadband would reduce the uncertainty in future CETL changes, which would improve the stability and predictability of RPM prices. An additional benefit of using a planning threshold slightly above the current 1.0 threshold is that it would allow for market-based opportunities to meet resource adequacy needs (*e.g.*, through QTUs, Customer-Funded Upgrades, or non-transmission alternatives), instead of pre-empting market-based solutions as soon as the ratio exceeds 1.0. Yet a 1.02 trigger likely would still be low enough to avoid serious reliability shortfalls in any given delivery year even if the market does not produce a solution.

While we do not propose specific values for the deadband boundaries, we propose two reasonable approaches for developing these numbers. As mentioned, one would be to base the high and low thresholds on the weather-normalized load forecast uncertainty. Under this approach a transmission project would not be planned unless it were, for example, 60% certain that it would be needed to meet the reliability requirement and would not be unplanned unless the chance that it would be needed to meet the reliability requirement dropped to 25%. A second approach would be to tie the deadband to the width of the VRR curve, such that small deviations from the target procurement level within the bounds anticipated under RPM would not be sufficient to trigger a transmission upgrade.

2. Modeling Transmission in RPM

One of the primary driving factors behind implementing RPM was the need to represent the locational value of capacity and reflect location-specific capacity shortages. Prior to the implementation of RPM, the Capacity Credit Market was not location-specific and could not address resource adequacy shortfalls in eastern PJM.[138] RPM was designed as a market-based *locational* capacity mechanism to provide efficient economic incentives for incremental capacity development in the locations where it is needed the most. To ensure that efficient economic incentives are produced by RPM, transmission capabilities must be represented accurately. We have generally found transmission representation under RPM to be implemented effectively, although we have identified refinements that could make RPM more robust to potential future locational modeling needs.

a. Determining Which LDAs to Model in Auctions

Partially in response to our 2008 report and effective for 2012/13 delivery year, PJM has revised LDA modeling rules such that more LDAs will be modeled in RPM auctions.[139] These new rules expanded the conditions under which LDAs will be modeled to include: (1) MAAC, SWMAAC, and EMAAC which will always be modeled; (2) LDAs with CETO $\leq$ 1.15 CETL; (3) LDAs that have price separated in any of the three previous BRAs; and (4) any LDAs that PJM expects may price separate.[140] These changes have been a beneficial addition in that they recognize that LDAs may price separate for economic reasons and may price separate in the future even if they have not price separated in the past.

[138] See PJM (2005), pp. 5-6.

[139] See PJM (2008f), pp. 50-53; Pfeifenberger and Newell (2008), pp. 104-109; PJM (2011d), pp. 11-12.

[140] See PJM (2011d), pp. 11-12.

Environmental regulations may introduce new locational resource adequacy challenges. We have seen, as discussed in Sections II and III.E, that RPM has so far proven robust in procuring the target capacity procurement despite the EPA HAP regulation expected to come into force during the 2014/15 delivery year. Sufficient capacity has been procured in all modeled LDAs. However, we have also observed that some zones that are not currently modeled as constrained LDAs have had a disproportionately large fraction of uncleared resources. In one currently unmodeled zone, the capacity of cleared resources for the 2014/15 delivery year dropped by 16% compared to the prior delivery year. Whether this particular reduction in committed resources creates locational resource adequacy concerns cannot be determined without also examining CETL for this zone, which has not been calculated. It is possible, however, that such a large reduction in LDA-internal resources could constrain the LDA even though it is not yet modeled in RPM.

While generators in PJM have the flexibility to avoid reporting their retirement until 90 days prior to the effective date, this does not mean that the *potential* for those retirements cannot be foreseen prior to the submission of deactivation requests.[141] There are both proactive and reactive ways to prevent potential resource adequacy and economic efficiency problems associated with zones that have not been modeled in RPM. In a proactive approach, PJM would more actively analyze which zones have a large fraction of capacity resources at risk for needing costly environmental upgrades. We understand that some analyses of this type have already begun in the context of the RTEP process.[142] Any area with a substantial amount of such resources that, if they were retired, would reduce the LDA below the 1.15 CETL/CETO threshold ratio could be modeled in RPM. A reactive approach would identify zones with substantial quantity of generating resources that have not cleared the prior BRA and, if the retirement of these resources would create a constrained LDA, model those zones in the remaining incremental auctions for that delivery year and the BRAs for subsequent delivery years.[143] Both of these approaches would provide safeguards against developing reliability problems develop in unmodeled LDAs.

b. Defining LDAs Based on Transmission Topology

As discussed in our 2008 report, it is important to recognize that transmission system capability may not in all cases be accurately represented by the traditional boundaries of transmission owners' service areas.[144] One example of how transmission constraints may not exactly conform to boundaries is the non-contiguous portion of APS, which is geographically entirely surrounded by the MAAC LDA, but modeled with the rest of APS as part of the unconstrained RTO under RPM.[145] Some stakeholders have suggested other LDAs that they believe should be modeled in

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141 Deactivation requests must be submitted to PJM at least 90 days prior to the proposed deactivation request, see PJM (2011p), p. 336.

142 For example, see PJM (2011p) and PJM (2011z).

143 It may even be possible to determine endogenously as part of the auction clearing process whether an LDA would be constrained based on the clearing of resources within the LDA.

144 See Pfeifenberger and Newell, et al (2008), pp. 103-109.

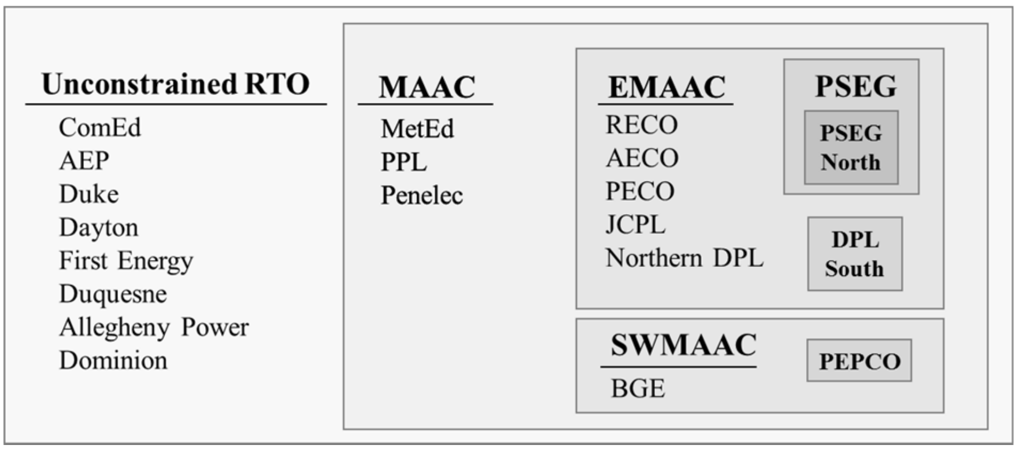
145 The non-contiguous portion of APS discussed here is in the middle of Pennsylvania surrounded by PENELEC and PPL zones, both of which are in the MAAC LDA. See PJM (2011s).

RPM, including the AP-South region, although we note that PJM already has a process by which stakeholders may identify such regions for consideration as new LDAs under RTEP.[146]

c. More Flexible Ways to Represent Transmission in RPM Auctions

RPM currently models transmission constraints using a nested LDA structure. Each LDA can import capacity from one "parent" LDA, and no LDAs are modeled with export constraints. Figure 25 is a schematic diagram showing this nested LDA structure. All modeled LDAs are shown in boxes with names in bold font. The names of transmission zones that are not currently modeled as LDAs are shown in regular font.

Figure 25
Nested Zonal Locational Deliverability Areas and Utility Service Areas



Sources and Notes:
Modeled LDAs are shown as squares with names in bold; other transmission zones are not currently modeled.
LDA definitions and structure from PJM (2011d), pp. 10-11.

This nested, import-constrained LDA structure has limitations in that it is not possible to represent all types of transmission constraints under this system. For example, this approach is not able to model: (1) export-constrained LDAs (including LDAs that may be either import-constrained or export-constrained); or (2) more complex transfer capability relationships in which import capability may be available from LDAs other than just the parent LDA. An example where this nested LDA structure may not work well is illustrated by the planned MAPP transmission project. Under the current structure, imports into the DPL-South zone must follow the path: RTO → MAAC → EMAAC → DPL-South. However, with the MAPP project, DPL-South would be able to import capacity from either of two directions, one along the path currently modeled through EMAAC, and another path introduced by the MAPP line: Dominion → PEPCO → DPL-South. The MAPP project would also directly connect PEPCO to Dominion, which would create an alternative import path for PEPCO.

More general LDA capacity transfer relationships of the sort described here could be better represented based on a "meshed" LDA framework as depicted schematically in Figure 26. The figure contrasts the current RPM approach (left panel), which is limited to nested import-constrained zones, to a more general meshed approach which *could* account for export

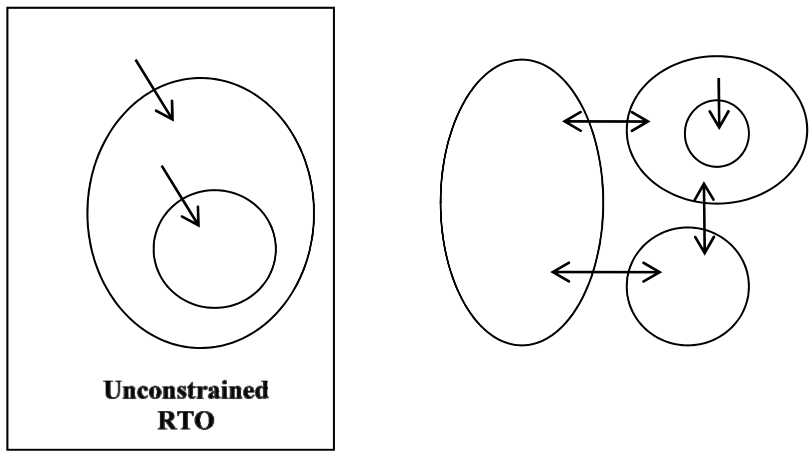
[146] See PJM (2011d), p. 12.

constraints, path-dependent constraints, and the potential for multiple import interfaces into some LDAs (right panel).

Figure 26
Nested Import-Constrained Approach vs. Meshed Approach to LDA Modeling

Nested Zones
Current RPM Design

Meshed Zones
Generalized Approach



It may not be critical to develop a more general approach to LDA modeling in the near term. However, as the excess capacity in the unconstrained RTO is reduced over time (*e.g.*, through environmental retirements), we expect that more LDAs will need to be modeled. As the number of LDAs increases, the current nested LDA structure may break down. In an extreme example, if all 25 LDAs needed to be modeled, a more general approach to modeling LDAs would certainly be necessary. The more general meshed zone framework is similar to what ISO-NE has proposed under new market rules, which will involve modeling all capacity zones in each Forward Capacity Auction (FCA).[147]

d. Summary of Recommendations for Transmission Modeling

With respect to transmission modeling in RPM, we have identified several potential refinements that PJM and stakeholders should consider in order to increase the likelihood that future resource adequacy needs and transmission constraints are accurately reflected in the RPM design.

- ***Model LDAs with Units at Risk for Retirement —*** To increase the likelihood that LDAs are modeled when needed for reliability and economic efficiency, we recommend identifying locations where a substantial number of units may retire.
  - ***Proactively Model LDAs based on Upcoming Environmental Regulations —*** We recommend that PJM and stakeholders continue ongoing efforts to identify units that may retire in response to new environmental rules. This could be done based on public data on emissions controls, stakeholder-submitted data on

[147] Additional complications and difficulties with a meshed zonal approach were also encountered in ISO-NE, but these were primarily related to difficulties in having a meshed zonal approach in combination with a descending-clock auction. PJM's sealed bid auction would not experience similar difficulties. See ISO-NE (2010), Section III.

individual plants, or IMM data from the 2014/15 BRA or other auctions. If the simultaneous retirement of the identified resources were to put a particular LDA below the 1.15 CETL/CETO threshold, PJM could consider proactively modeling that LDA in upcoming BRAs and incremental auctions.

  - ***Reactively Model LDAs based on BRA Results*** **—** We recommend that PJM examine post-BRA clearing results to identify LDAs that would drop below the 1.15 CETL/CETO threshold if uncleared resources were to retire. Specifically, we recommend that these LDAs be modeled in the remaining incremental auctions for that delivery year and BRAs for subsequent delivery years to avoid inefficient retirements and ensure procurement of sufficient resources.

- ***Define LDAs Based on Transmission Capability*** **—** While we have not specifically examined which LDA boundaries might need to be redefined, we reiterate our general recommendation from 2008 that LDAs are most appropriately and accurately defined electrically based on transmission constraints rather than by transmission provider territories. If electrically-defined LDAs would substantially differ from the current LDA definitions, PJM and stakeholders could consider revising these boundaries.
- ***Model Export-Constrained and Meshed Zones*** **—** We recommend that PJM and stakeholders consider generalizing the LDA concept beyond import constrained and nested LDAs. A more generalized "meshed" approach would be flexible enough to account for the potential for: (1) export-constrained zones; and (2) multiple import or export interfaces between individual LDAs that may not be accurately represented through nested LDA relationships.

3. Reducing Reliance on Reliability-Must-Run Contracts

a. Background and Concerns

Reliability must run (RMR) contracts are out-of-market backstop contracts used to prevent reliability problems that could occur when certain generating units retire. After a generator proposes to retire, PJM conducts a retirement study to determine whether reliability violations would occur. If reliability violations are identified, PJM may deny the deactivation request and offer to compensate the generation owner for keeping the generating unit online by signing an RMR contract. Such RMR contracts, while often necessary, are generally undesirable because they can be costly and will distort energy and capacity market prices.

In some markets, large out-of-market payments have also been indicators of problems in the market design. For example, the need to rely on several RMR agreements to ensure locational reliability under the prior capacity construct was one of the motivating factors for abandoning that design and implementing RPM.[148] Some stakeholders have indicated their concerns about the more recently-signed RMR contracts for Cromby 2, Eddystone 2, and Hudson 1, stating that

[148] See PJM (2005), pp. 5-6.

these contracts may indicate a deficiency in the RPM design, which was supposed to avoid such RMR backstop solutions.[149]

As we will discuss further in the context of coordinating RPM and RTEP, when evaluating whether a reliability concern can be addressed through RPM, one must distinguish between reliability concerns based on (1) localized transmission security, and (2) resource adequacy. Capacity markets are designed to address resource adequacy concerns. Thus, where a generation retirement would create highly localized transmission security violations, capacity markets are not well-suited to identify replacement capacity since adding resources in other locations within the same LDA would not resolve the problem. In this case, RMR contracts may temporarily be the only available solution if there is insufficient time to develop more cost-effective transmission or location-specific generation solutions. These types of transmission security violations do not indicate problems with RPM as they are generally unavoidable at the time of a specific generation retirement and could not have been prevented through additional capacity procurement from any other resources within the LDA. Our understanding is that the Cromby and Eddystone RMRs address such a transmission security violation. The Hudson RMR was also triggered by N-1-1 transmission security criteria violations, although the violations were far from Hudson and could presumably have been solved by adding generic resource within the LDA.[150]

If the retirement-related challenge creates a resource adequacy concern within an LDA, however, RMR contracts will generally not be an efficient solution to address the concern. A preferable solution would be to let the at-risk generation be replaced with other capacity resources procured within the LDA through RPM mechanisms, such as incremental auctions. Identifying the LDA-wide need and fostering such competition of resources within each LDA is precisely what RPM is intended to do. RPM offers a market-based alternative to RMR contracts that would address LDA-wide resource needs as long as the LDA reliability requirement is identified in the capacity auctions. However, there are several circumstances under which an LDA's reliability requirement might be understated in the auctions, causing RPM to under-procure sufficient market-based capacity resources in the LDA, potentially necessitating inefficient RMR contracts:

(1) If post-auction retirement studies include a stricter reliability standard than is included in the LDA reliability requirement for the auction, then retirement requests can result in inefficient RMR contracts. For example, if the binding constraint on LDA-wide need is an N-1-1 violation, it is considered a "transmission security" issue that is not considered in the LDA resource adequacy requirement for RPM purposes, *even if the violations could be addressed by any resource in the LDA.* The LDA reliability requirement is currently based on only an N-1 First Contingency Total Transfer Capability (FCTTC) analysis. Our understanding is that not recognizing the full LDA-wide resource need in the auction is what led to the Hudson RMR.

(2) CETL used in the auction could be higher than the transfer capabilities that are recalculated after the auction, for example, when resources that did not clear in the

[149] See, for example, MW Daily (2011). For additional documentation on these RMR contracts, see PJM (2011t), pp. 86-89.

[150] See Map 4.6 "PECO Zone: Upgrades Required by Eddystone and Cromby Retirements" and Map 4.7 "2012 Overloads — Hudson Unit 1 Retirement" in the RTEP [complete cite].

auction request deactivation. Such deactivation requests could reduce CETL by causing the pattern of electrical flows to change, thereby affecting the flows on the limiting transmission element.

(3) The CETO calculation assumes that all existing units will be available unless they have submitted a deactivation request. If this assumption overstates generation availability in an LDA (*e.g.*, because units that did not clear in previous auctions may be forced to retire), CETO will have been understated for the purpose of determining the auction parameters. Understating CETO can prevent the LDA from being modeled in the auction, thus not providing needed price signals and increasing the likelihood of having to rely on out-of-market RMR contracts for units that could have been committed through RPM if the LDA had been modeled.

b. Recommendations

To avoid these potential problems which could lead to inefficient RMR contracts, we recommend that PJM and stakeholders consider the following options. The first three options are presented in the order of potential problems discussed above:

- ***Set LDA Reliability Requirements Consistent with Certain Transmission Security Criteria That Would Be Used in Retirement Studies —*** We recommend that PJM determine whether any of the N-2 "transmission security" criteria that might lead to RMR contracts when existing generation seeks to retire could be addressed by any capacity within the same LDA (this will not be true of highly localized transmission security violations). Such criteria should be included in the LDA resource adequacy requirement used in RPM auctions so that the resource need is reflected in market prices and enough capacity can be procured within the LDA through RPM.
- ***Perform CETL Calculations Consistent with Auction Results —*** We recommend that PJM and stakeholders consider revising CETL calculations to account for resources that will likely not clear or have actually not cleared in RPM auctions. Because the determination of which units will not clear in RPM and, ultimately, may decide to retire cannot be foreseen perfectly at the time of the CETL calculation, this would be a difficult standard to achieve. Some options that could be considered, however, include:
  - Using information from prior auctions to anticipate potential retirements by removing units that have not cleared in recent RPM auctions. This may also affect CETL updates for incremental auctions by removing resources that did not clear in the BRA from the CETL analyses . If the retirement of uncleared units reduces CETL, it would allow needed resources to be procured in the incremental auctions and avoid reliance on RMR contracts.
  - When calculating CETL, LDA-internal capacity is ramped down and replaced with imports until the maximum capacity import limit is reached. These internal capacity resources could be dispatched down in descending order of the last BRA's offer prices (indicating the likely order of non-clearing units). This type of dispatch order might more accurately reflect the distribution of ultimately-available resources, resulting in more accurate estimates of future flows on critical transmission elements that determine LDA-wide needs.

- Another option would be to use bid data available to the IMM just prior to each auction to calculate CETL. In this case, CETL would be calculated based on an exclusion of any units that are offering into the BRA at high levels (as approved by the market monitor).
- It may also be possible to update CETL dynamically within the auction clearing process by making CETL dependent on whether certain large, key units fail to clear. This would require an analysis prior to the auction to estimate how CETL would change if certain key units were to become unavailable.

- ***Model LDAs More Proactively* —** Consistent with our recommendation in Section VI.A.2, some RMRs could be prevented by more actively identifying generation at risk for retirement and by modeling LDAs proactively when their CETL/CETO ratio is at risk to drop below the 1.15 threshold under a scenario in which some or all of the "at-risk" generation retires.
- ***Rely on Incremental Auctions to Avoid RMR Contracts*** — If reliability concerns caused by the announced retirement of a generating plant can be addressed by any type of capacity resource within the LDA, PJM could attempt to procure replacement capacity prior to the delivery year through the next incremental auction. An RMR contract would still be signed only if such resource procurement through an incremental auction is not possible.

4. Coordinating RPM and RTEP

a. Background and Concerns

Coordinating capacity markets and transmission planning is inherently difficult. Planning efforts for transmission and capacity resources are conducted by different entities and they occur at different times given the difference in project development timelines. In PJM, transmission planning is conducted on a five- to ten-year forward basis by PJM and its transmission owners, while planning efforts for capacity resources are conducted by competitive market participants through RPM participation, which is on a three-year forward basis. An additional difference is that the cost of transmission investments are recovered mostly through cost-of-service regulated tariffs, whereas the costs of capacity resources are recovered primarily in a market environment.

The two processes are inextricably linked, however, being dependent on each other and also sometimes representing alternative solutions to the same reliability concern. To coordinate these processes as effectively as possible, it is important to distinguish between transmission upgrades planned for two types of reliability concerns: (1) reliability concerns related to transmission security criteria, and (2) reliability concerns related to locational resource adequacy. For many transmission security needs, generation and DR alternatives do not exist. However, for locational resource adequacy needs, generation and DR alternatives do exist and the very purpose of RPM is to ensure efficient market-based incentives for them to be developed in the needed location.

We are concerned that the way the transmission planning framework for locational "reliability" addresses resource adequacy concerns can preempt market-based solutions under RPM. RTEP triggers transmission upgrades when the 5-year outlook projects a CETO/CETL ratio greater than 1.0. Because CETO is calculated as the locational resource adequacy requirement minus the expected amount of locational capacity resources, it includes an assumption about which capacity resources will be available within an LDA.[151] At that time, capacity market results are still unknown, which means that resource availability within the LDA, including any generation and DR additions and retirements, must be assumed. The CETO/CETL criterion will then require a transmission upgrade that could pre-empt a LDA-internal resource adequacy solution that may otherwise have been developed under RPM. Once the CETO/CETL criterion is triggered in transmission planning, there is little opportunity for new generation or DR to meet the identified resource need even if doing so would be less expensive than the planned transmission upgrade. Ideally, generation and DR solutions would be allowed to compete with transmission, and a market-based solution to LDA-level resource adequacy needs (as opposed to more location-specific transmission security issues) would be identified and committed through RPM.

b. Recommendations

We understand that PJM is currently reviewing its RTEP process and recommend that PJM explore the possibility of adding an additional economic planning component to RTEP. The additional economic criterion we propose here for evaluating resource adequacy-driven "reliability" projects would have a fundamentally different purpose from the current mechanism for identifying "market efficiency" upgrades under RTEP.[152] The current economic upgrades process is intended to allow for the development of transmission projects that are not needed for reliability purposes but that are desirable for purely economic reasons. The additional economic criterion that we propose here would be a threshold applied to the approval of reliability-driven transmission projects for which there are LDA-internal capacity alternatives. Such a transmission project would only be approved if the transmission solution is found to be less expensive than the expected cost of LDA-internal capacity alternatives. We have not conducted a comprehensive review of how such criteria could be structured within RTEP, but recommend that PJM and its stakeholders further evaluate these options as part of the ongoing RTEP review process:

- ***Consider Economic Criteria in RTEP for Reliability Projects —*** We recommend that PJM and stakeholders consider adding economic criteria to the evaluation of transmission projects that are planned primarily to meet locational resource adequacy requirements as represented by the CETO/CETL ratio. An economic criterion could, for example, require that such a transmission project would be pursued only if were cost-effective compared to generic LDA-internal generation additions that could similarly address the identified reliability concern (*e.g.*, the addition of a combustion turbine at a cost equal to Net CONE). We have not conducted a comprehensive review of how such criteria could be structured within RTEP, but recommend that PJM and its stakeholders further evaluate these options as part of the ongoing RTEP review process.

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[151] See PJM (2011i), p. 53.

[152] See PJM (2011i), Sections 1.3.2, 1.5.2, 2.6 and Attachment E.

B. LOAD FORECASTING

1. Background

Stakeholders representing load and some of the state commissions raised concerns over the accuracy, economic efficiency, and transparency of reliability targets and load forecasts. Their concerns with reliability targets have been discussed in Section III.G of this report. This section addresses whether the load forecasting process could be improved to support greater transparency, predictability, and market confidence.

2. Analysis

It is invariably the case that future peak loads are uncertain and cannot be forecasted with great accuracy. Moreover, both actual future loads as well as the load forecasts themselves will change with economic market conditions and other factors. Just as it is not possible to forecast economic growth with great accuracy, it will not be possible to forecast future peak loads with any more certainty. In fact, uncertainty over future economic growth will magnify uncertainty in load forecasts. The drop in loads and load forecast in response to the unanticipated poor economic conditions over the last several years presents a good example of this type of uncertainty.

That load forecasts are uncertain also means that load forecasts for future delivery years will necessarily change over time as new forecasts are developed based on updated economic and other data. This uncertainty in load forecasts will consequently be one of the administratively-determined parameters that contribute significantly to uncertainty in capacity costs and RPM payments. Changes in load forecasts affect RPM payments through several mechanisms: (1) the total amount of capacity that needs to be procured on a system-wide and LDA basis; (2) the price at which that capacity clears; and (3) the extent to which prices within individual LDAs will separate from RTO-wide levels. For example, the 2014 system-wide summer coincident peak load forecast updated earlier this year was approximately 4,200 MW (approximately 2.8%) lower than the 2014 load forecast made in early 2010.[153] While the new forecast will be a more accurate estimate of likely future peak loads, the adjustment necessarily has significant implications for RPM. At an RPM clearing price of $130/MW-day for the 2014/15 delivery year, this change reduced RPM capacity payments by approximately $200 million per year due to the lower quantity procured, even before considering the impact in reducing the clearing prices.

Load forecasts will additionally affect RPM through CETL determinations and the transmission planning process. The transmission planning process identifies reliability violations and new transmission facilities needed to address these violations, but the process also delays previously-planned transmission facilities if updated load forecasts no longer result in reliability violations. For the purpose of transmission planning and RPM-related CETL determination, it is also necessary to estimate how the total load for a load zone is distributed within each zone. Changes

[153] From 145,829 MW and 149,998 MW 2014 summer coincident peak load forecast without ATSI or DEOK from the 2010 and 2011 load forecast reports, respectively. See PJM (2010c), p. 29 and PJM (2011e), p. 30.

in the estimated distribution of load within a zone can be as consequential as changes in the total load for that zone because of the impact of the load distribution on CETL calculations.

Given the size of the PJM market area, the largest organized power market in the world, and the associated magnitude of the dollar impacts related to even fairly modest changes in load forecasts, it is also increasingly important to assure to the greatest degree reasonable that:

1. Changes in load forecasts reflect to the largest degree possible the true changes in market fundamentals and a consensus of expectations regarding economic conditions three years into the future;

2. Both system planners and market participants are aware of inherent load forecasting uncertainties and are informed about the likely magnitude of this uncertainty; and

3. The load forecasting process utilizes best available practices and forecasting models that are transparent, understood, and accepted by market participants.

This requires that the load forecasting process is designed to minimize the likelihood of errors introduced by the load forecast development and review process. To avoid excessive uncertainty in RPM clearing prices and total annual payments, it would also beneficial to reduce fluctuations in load forecasts that are solely due to unavoidable statistical uncertainty of the underlying forecasting models.

3. Recommendations

PJM is fully aware of these factors and is already engaged in a review to improve its load forecasting model, involving stakeholder input through the Load Analysis Subcommittee (LAS) and Planning Committee. We do not offer specific recommendations about these current efforts to improve the PJM load *forecasting model* itself. However, in light of stakeholder concerns and the importance of load forecasting for RPM, we offer the following recommendations regarding PJM's *forecasting process* for further consideration, individually or in combination:

- ***Improve Stakeholder understanding of updated load-forecasts***. We recommend that PJM consider expanding the documentation and narrative explanation of its updated load forecasts. Each time an official new load forecast is issued, PJM would provide to stakeholders: (1) documentation of the changes in load forecasts and model input data from the prior forecast; (2) a full analysis and narrative explanation of the reasons for the observed changes in load forecasts (*e.g.*, changes in model coefficients or changes historical and forecast dependent variables such as economic growth); and (3) documentation of changes (if any) in how load forecasts are distributed within load zones for transmission planning and RPM-related CETL determinations. It may also be possible to provide this information for stakeholder review of a preliminary load forecast that could then be finalized with stakeholder feedback.

- ***Provide Estimates of Forecasting Uncertainty***. We recommend that PJM consider providing statistical estimates of the uncertainty of its weather-normalized long-term load forecasts. Uncertainty could be expressed as confidence intervals (*e.g.*, a 50%, 75% and 90% confidence band) for weather-normalized load forecasts for each of the next 10 years, including an estimate of the portion of the uncertainty caused by the uncertainty of key explanatory variables such as economic growth. (Because planning reserve margins are based on peak load forecasts for normal weather, weather-related load uncertainties used for transmission planning and reliability studies, such as forecasts of 50/50 and 90/10 loads, should be quantified separately.)

- ***Continue existing efforts to refine the load forecasting model***. We recognize PJM's current effort, through the LAS, to improve its load forecasting model, and we recommend continuation of this effort. This ongoing effort might additionally explore assessing the extent to which different model specifications and independent variables (*e.g.*, different data sources of economic growth forecasts) might be able to improve the model's multi-year forecasting error as an objective distinct from current effort to improve the model's backcasting accuracy. Within the current effort, we also recommend that PJM explore available options that might be able to reduce changes in load forecasts due to statistical uncertainty without suppressing changes in load forecasts due to changes in market fundamentals. (Documenting changes in load forecasts due to changes in economic forecasts and changes in model coefficients may be helpful in that regard).

- ***Consider Sharing Semi-Annual Preliminary Updates to PJM's Load Forecast***. We recommend that PJM consider releasing preliminary updates to its previous load forecast and associated preliminary changes to RPM parameters (*i.e.*, target RTO-wide and LDA-specific procurement levels). These preliminary updates would be solely informational and not be used for any planning or market operations purposes. We believe the release of such preliminary updates would increase transparency and reduce uncertainty because it would: (1) allow trends and changes in RPM parameters to become visible earlier to market participants; (2) increase stakeholder understanding and acceptance of the forecasting process and how it affects RPM; and (3) provide a better sense of changes in market fundamentals and forward-looking forecasting uncertainty.

- ***Collect UDC load forecasts as additional reference points***. We recommend that PJM and stakeholders consider collecting (if necessary on a confidential basis) any long-term load forecasts that are routinely prepared and updated by individual utility distribution companies and/or load serving entities. These UDC and LSE load forecasts would provide a reference point to PJM's own forecasts of the individual zones' peak loads. Comparing the level of these forecasts and how they change over time would serve as an additional tool to validate PJM's own forecasts, confirm observed trends and changes, and provide an additional safeguard against inadvertent errors in the forecasting process.

- ***Possibly Retain Academic Advisors to the PJM Load Forecasting Team***. We recommend that PJM explore the benefits of retaining two or three academic advisors available as a standing resource to the PJM load forecasting group. These advisors would be able to contribute significant theoretical and applied experience in the field of econometric forecasting, be available to PJM's load forecasting group as a resource, assist PJM in obtaining and maintaining a "best available practices" standard for both the forecasting process and the econometric model itself, and evaluate the soundness of proposed changes to the forecasting process and forecasting model.

We recognize that the full development and implementation of any of the above recommendations would likely require additional resources dedicated to PJM's load forecasting function. However, given the importance and monetary implications of PJM's load forecasting functions in terms of RPM and transmission planning, the incremental cost of these resource requirements will likely be small compared to the benefits. The benefits also include increased transparency, improved forecasting data and processes, and the economic benefits of being able to reflect a better understanding of long-term load forecasting uncertainty in PJM transmission planning and stakeholder investment decisions.

C. Comparability of Capacity Resource Types

One of the original objectives of RPM was to allow different capacity resource types to compete in meeting PJM's resource adequacy requirements. To ensure that resource adequacy is achieved at the lowest cost, it is important to ensure that all resources capable of providing capacity can participate in RPM and that resources providing comparable capacity receive comparable treatment.

We find that PJM's incorporation of multiple types of demand resources (DR) is one of RPM's greatest successes. The successful integration of DR also helps to achieve resource adequacy at a lower cost. PJM has already addressed the two most important original design issues that arose as the amount of DR increased: (1) starting with the 2012/13 delivery year, it fully integrated DR into RPM by eliminating the ILR option; and (2) starting with the 2014/15 delivery year, it established differentiated DR products recognizing that DR that allows for only limited dispatch and has only seasonal availability has less capacity value than year-round availability of unlimited resources.

However, some stakeholders have emphasized that with DR approaching 10% of RPM-cleared capacity, including two new, untested products, the comparability of DR to other resource types should be reassessed. We thus evaluate: (1) the new multi-product construct to accommodate different types of DR resources; (2) existing mechanisms to verify and enforce that resources committed in RPM will perform as promised; (3) the determination of the (UCAP) capacity value for DR; and (4) potential future directions to recognize the capacity value of other non-traditional resources.

We find that PJM's existing design largely addresses stakeholder concerns. However, we recommend some refinements to further improve the efficiency of RPM and to ensure that all resources can perform as claimed. Our primary recommendation is to consider expanding the resource registration process just before each delivery year to include audits of random samples of contracts and the nature of loads that will be reduced. Annual DR resources must be able to respond in all seasons and not be constrained by contractual limitations on the number of calls. Extended Summer resources must also be unconstrained in the number of calls. This will allow PJM to confirm that resources can respond as frequently as claimed. Such verification and potential deficiency penalties will provide strong incentives to DR providers to make their offers and commitments consistent with ultimate capabilities. However, since only a small fraction of DR committed in the 2014/15 auction cleared as Annual or Extended Summer DR, this mostly addresses a potential concern about commitments made in future auctions.

1. Multiple Products to Accommodate Different Types of DR

In response to the rapid growth of DR in RPM, PJM recently conducted a demand response saturation analysis[154] that assessed the impact of Limited DR replacing year-round (annual) generation capacity at a relatively large scale.[155] The primary concern was that extensive reliance on Limited DR—which can be curtailed no more than ten times a year, for only up to six hours during each event, and only during the summer months—could lead to reliability problems. As DR displaces larger amounts of generation capacity, it could be needed to curtail more often, for longer durations, or during months when Limited DR is not obligated to curtail. This was not a concern at low levels of DR penetration because the chance that a DR resource would be called more often than its capacity obligation allows was very small. PJM's DR saturation analysis indicated that reliability problems were likely if PJM continued to rely on Limited DR at higher levels of penetration.[156]

There were several options available to address this concern. One was to redefine the obligations of DR from a limited (10x6) capacity resource to an annual resource by requiring them to be ready and available during the entire delivery year, just like generation capacity committed under RPM.[157] Another option was to retain the Limited DR resource type while adding a new, unlimited DR resource type. PJM opted for a hybrid approach to resolve the identified reliability risks by adding two new DR resource types starting with the 2014/2015 delivery year: Annual DR and Extended Summer DR. Although these products can be called upon more often than the Limited DR, neither of the two new products must be available at all times. Extended Summer DR is required to be available every day during a six-month extended summer period, May through October (compared to up to 10 times from June through September for Limited DR) and must be able to maintain load curtailments for up to 10 hours per event (compared to up to 6 hours for Limited DR). Annual DR must be available every day of the delivery year except during PJM-approved maintenance outages. The duration of events during which it must respond is limited to 12 hours from May through October, and to 15 hours from November through April. Annual resources include the newly-defined Annual DR and other annual resource types which are generally required to be available at all times, such as generation, but also energy efficiency. Extended Summer resources include all Annual resources and the newly-

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154 PJM Interconnection, L.L.C., Exhibit 1 of the Tariff filing to FERC in Docket No. ER11-2288-000, submitted on December 2, 2010 and approved by FERC on January 31, 2011.

155 Prior to the 2014/15 delivery year, the RPM design recognized only one type of DR that had limited obligations both in terms of the frequency, duration, and the timing of events during which it was required to respond. In the remainder of this section we refer to this resource type as "Limited DR".

156 PJM's analysis found that, at a 90% confidence level, the penetration of Limited (10x6) DR should not exceed 4.7% of peak load, in order to ensure that PJM would not need these resources more often, or request longer curtailments, than their obligation. An earlier analysis conducted by PJM found that reliability would not be affected at DR penetration below 7.5% of peak load, however that study was conducted using less sophisticated tools and analytical methods.

157 This approach is favored by PJM's Independent Market Monitor, arguing that "the potential benefit of an unlimited demand-side product will not be realized without the elimination of the current flawed DR product." See Monitoring Analytics LLC, *2010 State of the Market Report for PJM*, page 118. This approach has also been implemented in other markets. For example, in ISO New England's Forward Capacity Market, demand resources must provide an annual capacity product (although they can combine with complementary resources).

defined Extended Summer DR (*i.e.*, all resources that must be available at least as often as Extended Summer DR).

The new design ensures that an adequate amount of Annual and Extended Summer resources is procured in RPM by setting a minimum amount of these two types of capacity that must be procured for the RTO and each LDA in each base auction.[158] The auction clearing mechanism treats the two new minimum capacity constraints in a similar manner as it treats transmission constraints (*i.e.*, to clear a minimum amount of local capacity). DR that qualifies as two or more of the DR types may submit separate but coupled offers for each DR type.[159] The auction clearing algorithm selects the offer that yields the least-cost overall capacity procurement. It will choose resources out of merit order if any of the minimum capacity constraints is binding. Prices may rise to clear additional Annual or Extended Summer DR, if needed, and those higher prices will be awarded for Annual and Extended Summer resources, but not for Limited DR. The price adders for Annual and Extended Summer resources reflect the additional value of unforced capacity required to meet the minimum capacity requirements. As a result of the recent market design change, price separation in RPM can now occur not just by location but also by resource type.[160]

PJM held its first BRA under the new design in May 2011 for the 2014/2015 delivery year. The auctions appear to be working as planned. In the auction, more than half (9,253 MW) of all DR resources submitted linked offers as Annual DR with an unlimited number of calls. Only 511 MW of Annual DR offers cleared, and 1,441 MW of Extended Summer, and 12,166 MW of Limited DR.

Overall, we conclude that the recently implemented change to the RPM market design was a reasonable and effective solution to a valid concern. However, the introduction of multiple capacity products for DR raises the question whether other kinds of resources should be allowed to be classified by product type. In this context we offer the following recommendations:

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158 The minimum amounts of Extended Summer resources are derived from the Reliability Requirement (reduced by the 2.5% Short-Term Resource Procurement Target) minus the maximum reliable amount of Limited DR. The maximum reliable amount of Limited DR is determined in a probabilistic analysis that identifies the level of DR where the probability that PJM will require 10 or more interruptions is less than 10% and the chance that it would require interruptions longer than six hours is relatively low. A similar analysis is used to establish the minimum amount of Annual resources and maximum reliable amount of Extended Summer resources. The maximum amount is the level of DR penetration at which the annual LOLE is 10% higher than the LOLE of a reference scenario with DR penetration of zero.

159 In other words, a single resource may have up to three linked offers, one each for Limited, Extended Summer, and Annual DR, but only one of those offers may clear in the auction.

160 PJM's Independent Market Monitor disagrees with some aspects of the new design, namely the introduction of the Extended Summer DR product and the retention of Limited DR, which it views as a "flawed" capacity product. The IMM argued that reliance on Limited DR may compromise reliability and the overall capacity market design, and the addition of new DR products adds unnecessary complexity and creates an illiquid market for these products. Protest of the Independent Market Monitor for PJM, filed with FERC in Docket No. Docket No. ER11-2288-000 on December 20, 2010.

- ***Reclassifying Energy Efficiency based on capability.*** Energy efficiency is currently considered an annual product,[161] even though it is providing load reductions during a limited period.[162] We recommend that PJM consider classifying energy efficiency based on the periods when it can actually perform. For example, while energy efficient lighting would be an Annual resource, more energy efficient air conditioners could be classified as Extended Summer rather than Annual resources.

- ***Allow for Seasonal Generation.*** Generation capacity with seasonal (summer-only) availability cannot participate in RPM, because generators must offer an annual product. We recommend that PJM consider allowing such generation to participate as Limited resources. PJM could also consider allowing all generation that is submitting offers as Annual resources to also submit lower-priced linked bids as Limited capacity, reflecting the lower costs of committing the unit for the summer only.

2. Assurances of DR Performance

Forward capacity markets need to have mechanisms in place to ensure that committed resources, both existing and planned at the time of the BRA, will be available during the delivery year to fulfill their capacity obligations. Existing generating resources may face the risk of costly environmental retrofits or other major unexpected capital expenditures to stay online. Planned generation or demand-side resources face the risk of unexpected cost increases or delays. Untested products face the additional risk that actual circumstances during which they have to respond may be very different from what is currently expected. In this section, we focus on DR performance because of its high recent growth, but also to address stakeholder concerns about whether DR capacity is comparable to generation. More specifically, our primary focus is to explore whether existing measures will ensure that: (1) CSPs have sufficient incentive to submit realistically achievable DR plans; and (2) CSPs face sufficient verification and penalties if they were to misrepresent limited resources as unlimited resources.

PJM already has several stages of verification—including qualification, tracking development, registration, and performance and testing—and penalty and incentive mechanisms in place. There are several stages to validate the quality of new capacity resources and to assess the likelihood that they will be able to perform as expected during the delivery year. These stages include qualification of resources for the BRA, tracking the whether committed resources achieve various milestones prior to the delivery year, and penalizing resources for under-performance during the delivery year. We reviewed the milestones that planned resources in RPM must meet to avoid penalties due to non-compliance with their capacity obligations.

Table 1 Table 25 below summarizes each of these milestones for planned DR, actions taken by PJM at each milestone, as well as potential enhancements to the current process, as discussed below.

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161 PJM Tariff, Attachment DD, Section 2.1B.

162 The performance hours for energy efficiency are between hour ending 15 Eastern Prevailing Time (EPT) and the hour ending 18 EPT from June 1 through August 31, excluding weekends and federal holidays. See Section 1.20A and Schedule 6 of the PJM Reliability Assurance Agreement.

a. Qualification

All resources must meet the qualification requirements for the BRA no later than approximately two weeks before the auction. For planned DR, this process consists of a review of the resource provider's DR plan and the posting of credit. A DR plan consists of basic information about the project, such as the aggregator's plan to procure customers, project milestones, and the nominated DR value, including the underlying assumptions used to derive it. Since these resources do not exist at the time of the auction, the evaluation of DR plans must be based on the credibility of the plan. It is important to ensure the process of reviewing DR plans is effective. However, we did not identify any potential enhancements for this stage of verification.

b. Tracking the Development of New Resources

The next stage is the tracking of new resources committed in RPM, which takes place between the BRA and the start of the delivery year. PJM may verify that a planned DR adheres to its DR plan at any time, but there is no pre-determined schedule of required progress reports. Furthermore, there appear to be no penalties for not following the DR plan. In contrast, ISO New England requires regular quarterly updates, and planned resources experiencing delays risk losing their posted credit and their capacity obligation if the planned online date moves beyond the start of the delivery year due to the delay.[163] We recommend introducing ***periodic update requirements from planned resources*** (*e.g.*, just before each incremental auction) as this would provide a clear indication whether planned resources are on track to be completed by the start of the delivery year.

c. Registration in Emergency Load Response Program

Registration in PJM's Emergency Load Response Program is the final step before the delivery year. It must be completed and approved before the start of the delivery year to avoid deficiency penalties. As part of the registration process, customer-specific data (*e.g.*, peak load contribution) must be provided to PJM. The registration process is largely an administrative step and does not involve any verification by PJM of the resource's ability to perform.[164] Since at this step planned resources must be at their final stage of development—with actual end-users and contracts in place—we recommend that PJM ***consider verifying that the CSP has the physical or contractual capability to curtail as often and seasonally as required***. For example, we believe that air conditioning load and event-limited contracts should not be able to register as Annual DR (given that no curtailments can be provided outside the air conditioning season), except perhaps as a discounted part of a larger, sufficiently balanced portfolio. Although DR resources are required to test during the delivery year, those tests do not check how frequently a resource would be able to curtail if called frequently or across seasons.

This is the most important enhancement we recommend. Adding such verification (and the threat of deficiency penalties) would provide additional incentives to CSPs to make sure their programs meet required capabilities. A comprehensive audit of all DR contracts may be too burdensome, but PJM could select a random sample for contractual audits (*e.g.*, a CSP's

[163] ISO New England Market Rule 1, Section III.13.3.4.

[164] Although PJM does not currently verify resources ability to perform in the registration process, EDCs and LSEs review DR programs to ensure that the customer physically exists and is not double counted.

portfolio of resources in a single zone). PJM could address audit failures by applying penalties (*e.g.*, deficiency penalties to the CSP's entire PJM-wide portfolio) and/or referring the CSP to FERC.

Table 25
Verification of Planned DR

Activity	Timing	Assurances & Verification in Place	Potential Enhancements
Qualification of New Resources	At least 15 days prior to an RPM auction	**Review of DR Plan (**project description; customer recruiting plan & milestones; MW value of DR; key assumptions) **Verification of RPM Credit Limit** **"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	January through 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 random 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.

d. Performance Assessment and Testing during the Delivery year

The pre-auction validation process is followed by performance assessment and testing during the delivery year. Under normal, expected conditions, there may not be many actual load management events called in the delivery year. This limits PJM's ability to discover how DR resources (or portfolios) would perform under unexpectedly tight market conditions (*e.g.*, due to an extended heat wave and major plant outages) when their capacity is most needed and calls are more frequent. To prevent CSPs from overstating their capabilities, we recommend a more rigorous verification process prior to (and possibly also during) the delivery year as discussed above.

Performance verification during the delivery years is also important. In case there are no dispatch events at all, testing is important for verifying that CSPs can produce the total committed number of MW in each zone in a single call. The current testing process works as follows: DR providers are required to conduct a one-hour simultaneous test of all their resources in a zone if PJM does not otherwise initiate an actual load management event in that zone. They are allowed to choose the timing of the test, as long as it falls within the hours of the summer period when the resources are obligated to respond, and notify PJM 48 hours in advance. If less than one quarter of the resources fail a test, the provider is allowed to retest the subset of resources that failed. There is no current limit on the number of tests that may be conducted, and the provider can submit the single most favorable of all the test results.

The fact that CSPs may conduct an unlimited number of tests and submit only the results for the test of their choosing raises the concern that those tests results may not reflect the resource's actual ability to respond on a consistent basis. Therefore, we recommend that PJM ***consider adding random PJM-initiated tests to the current testing procedures, and limit CSPs' ability to selectively pick the test results***. Furthermore, we recommend ***extending the duration of the tests to a multi-hour period***, consistent with the fact these resource are required to respond for a period of several consecutive hours.

e. Comparability of Penalty Mechanisms

Performance needs to be supported by penalties for under-performance. Such penalties should ensure that suppliers have the incentive to make resources available and guarantee their performance during the delivery year. Comparability of obligations and penalties across resource type also ensures that the different resource types compete on a level playing field.

PJM has two general types of penalties. A supplier is subject to a *deficiency penalty* if it is unable to provide all or part of its committed capacity in time for and during the delivery year. *Performance penalties* apply when the supplier's committed resources do not perform adequately when called upon. Performance can be measured by various metrics during peak periods, testing, or other PJM-initiated events. Table 26 below compares penalties applicable to DR to those applicable to generation resources.

The penalties in Table 26 are grouped into the following categories: deficiency, availability, test failure, and other. Each penalty is decomposed into two components: (1) basis for penalty (for failing to meet a certain obligation, usually not providing the committed UCAP MW); and (2) the penalty rate, which is the rate at which an unfulfilled obligation is penalized (usually in terms of $/MW-day or $/event).[165] The Daily Deficiency Charge, which is the higher of 120% of the resource clearing price or the resource clearing price plus $20/MW-day, is the penalty rate for failing to meet several obligations, including capacity deficiencies, peak-season maintenance, and resource tests.

[165] Some charges can turn into a credit if the resource over-performs; thus they penalize under-performance while incentivize good performance.

Table 26
Comparison of RPM Penalties for Generators and DR & ILR

		Penalty Rate		
Penalty	**Basis for Penalty**	**Generators**	**DR**	**ILR**
Deficiency Penalties				
Capacity Resource Deficiency Charge	Daily shortfall between committed and actual capacity	Wtd Avg RCP[1]+ Max[0.2×Wtd Avg RCP; $20/MW-day] *(Daily Deficiency Rate)*		N/A
Availability Penalties				
Peak Season Maintenance Compliance Penalty Charge	UCAP shortfall due to unapproved maintenance or planned outages during peak season	Wtd Avg RCP + Max(0.2 Wtd Avg RCP; $20/MW-day) *(Daily Deficiency Rate)*	N/A	
Peak-Hour Period Availability Charge/Credit[2]	Daily Net[3] Peak-Hour Period Capacity Shortfall (max. to a cap that gradually increases from 0.5 × UCAP to1 × UCAP by the third consecutive year of limited availability)	Wtd Avg RCP	N/A	
DR and ILR Compliance Penalty Charge/Credit	Under-compliance (positive difference between committed MW and actual load reduction) during Load Management events[4]	N/A	*On-peak periods*: Min [(1/(# of events); 0.5] × Wtd Avg Annual Revenue Rate[5] *Off-peak periods*: 1/52 × Wtd Avg Annual Revenue Rate	
Test Failure Penalties				
Test Failure Charge	Shortfall between committed and tested capacity	Wtd Avg RCP + Max(0.2 Wtd Avg RCP; $20/MW-day) *(Daily Deficiency Rate)*		
Other Penalties				
Emergency Procedures Charges	Failure to comply with PJM instructions during emergencies	Number of days in the DY x Daily Deficiency Rate x Under-compliance MW		
RPM Must-Offer Requirement Failure Penalty	Failure of existing generators to offer into a BRA	Not allowed to participated in any incremental auction or be used to satisfy any LSE's UCAP obligation; further action by IMM	N/A	

Notes:
[1] Weighted average Resource Clearing Price of a portfolio in an LDA across all RPM auctions.
[2] The amount collected in Peak-Hour Period Availability penalties is credited to resource providers with negative net capacity shortfalls, subject to cap of Net Peak-Hour Period Capacity Shortfall times their weighted average RCP in the LDA.
[3] The netting of Peak-Hour Period Capacity shortfall is performed across committed units by seller (*i.e.*, single eRPM account) in an LDA. Uncommitted capacity by the same seller may be used to offset shortfalls by committed capacity (provided uncommitted capacity is in the same LDA).
[4] Performance is assessed on a portfolio-basis by each seller in a given zone.
[5] Annual Revenue Rate is the RCP from the RPM auction where the resource was committed.

We conclude that penalty rates for DR and generation are comparable, with only a few exceptions noted below. They are now more comparable than in the early RPM design when, for example, when DR was not subject to test failure penalties and ILR was not subject to deficiency penalties due to its timing.[166] Some penalties, namely the peak-hour availability and peak-season maintenance compliance penalties apply only to generators. The rationale could be that DR is an idiosyncratic resource with availability that may be difficult to measure.

3. UCAP Value of DR Products

In order for DR resources to participate in RPM, they must be assigned an unforced capacity (UCAP) value. However, the traditional availability metrics used to calculate UCAP for generation are not necessarily applicable to DR because the nature of loads underlying DR is much more varied than the capacity of generation technologies. Therefore, the UCAP value of DR must be measured differently. The current method used in RPM is to multiply the nominated value of DR by the Forecast Pool Requirement ("FPR") and the DR Factor.[167] The FPR grosses up the nominated value of DR for reserves (in UCAP terms) based on the rationale that if DR commits to be curtailed then PJM will not need to procure reserves for the underlying load — as if the load reduction were a reduction in the peak load forecast whose magnitude is perfectly correlated with system load. The DR Factor is based on the Effective Load Carrying Capability ("ELLC") of the resource and accounts for the fact that the resource may not always be available to serve PJM's capacity needs.

The current method of calculating UCAP value for DR seems slightly inaccurate in different ways for each type of DR. A more accurate method would result in a UCAP value that better reflects the reduced capacity need as a result of the load curtailment. The method of calculating the UCAP value of DR should take into account the type of load curtailment that the resource is committed to provide. DR that commits to curtail load *by a given amount* under the Guaranteed Load Drop (GLD) option is very similar to generation, and therefore it should be assigned a comparable capacity value, without any need for adjustment using the current DR Factor and FPR Factor.

However, DR that commits to curtail load *to a pre-determined level* under the Firm Service Level ("FSL") option provides greater value and should be assigned a higher UCAP value accordingly. The following example illustrates this point. Suppose a customer whose load is perfectly correlated with the system load has a 100 MW coincidental peak load forecast (all figures are assumed to be at the bus-bar level, already grossed up from the metered load for transmission losses). PJM will need to procure 108 MW of UCAP for this customer, assuming a typical FPR value of 108%. However, if the customer agrees to curtail its load to 90 MW whenever PJM calls on it under the FSL DR option, only 90 MW of UCAP is needed to serve the customer. Since this reduces the capacity need by 18 MW, the DR should be assigned a capacity value of 18 MW, ignoring unavailability. However, if the customer is not under supervisory control or is not able to curtail under all circumstances, the full 18 MW may be excessive. For example, if a customer's *forecasted* load were reduced to 90 MW, without a guaranteed curtailment to that level, then the value of that load reduction would be 10.8 MW (change in load forecast multiplied by an FPR of 8%). Thus, even in that worst case, FSL-type DR should be assigned a UCAP value that continues to be grossed up by the FPR Factor, but without the

166 Penalties will become even more comparable after the ILR option is eliminated starting with the 2012/2013 delivery year.

167 Nominated value of DR is determined by the resource owner, and is akin to ICAP for generation.

discount currently applied through the DR Factor. The assigned UCAP value could be even higher for FSL under firm supervisory control.

As a separate issue, PJM's current method of determining UCAP value of existing DR ignores past performance, in contrast with UCAP value of generation. For generation, a one-year average EFORd is used to calculate its UCAP value for each delivery year. If the resource under-performs in previous years, its EFORd and UCAP value will reflect that fact. Therefore, generators are implicitly penalized for past weak performance. It would be reasonable to add a comparable adjustment to the UCAP value of DR resources. Unlike generation, capacity of DR depends more on the CSP's ability to manage its portfolio that on the quality of the underlying resource. Therefore it is should be assumed that if a CSPs portfolio underperformed in the past, it is likely to underperform in the future. This assumption could be maintained until the CSP proves otherwise. If a shortfall occurs due to derated DR capacity, replacement capacity can be procured in the incremental auctions.

4. The Present Proceeding Affecting GLD Value and Participation

PJM and its Independent Market Monitor recently identified an issue regarding the Guaranteed Load Drop ("GLD") option used for measuring the performance of DR that chooses this method.[168] The key issue in this "double-counting" debate is how to measure compliance against the nominated (and committed) amount of DR and what should be the appropriate reference point or baseline. PJM has argued that allowing DR to measure its performance against a baseline that depends on recent load levels (effectively, the same baseline as the one used in the energy market) may provide an incentive for curtailment service providers to include assets in their portfolios with little ability to perform because over-performance by other assets in the portfolio will often allow the portfolio to perform at the expected level.[169] PJM analysis has indicated that this issue could result in the commitment of a large number of low-quality DR which could lead to future reliability problems. For example, during super-peak hours high-quality DR resources may be able to perform (*i.e.*, curtail to their peak load contribution, or "PLC") but not over-perform, while low-quality DR may under-perform. As a result, PJM may be, on aggregate, short on capacity when the amount of low-quality DR is relatively large. To address this, PJM has filed its proposal with FERC that would cap the baseline under the GLD option at each resource's PLC.

We are not commenting on the overall merits of PJM's proposal because it is being addressed in a separate proceeding, and we have not analyzed the need for PJM's proposal or its implications. However, we acknowledge stakeholder concerns that limiting DR contributions to reductions below a customer's PLC could impair the GLD option for some end users. End-users with a highly variable and unpredictable total load can often and legitimately experience unrestricted total load in excess of their PLC (which is based on peak loads during the year prior to the delivery year). Thus, they may not be allowed to fully take credit even for definitive actions to shed a portion of their load, such as

[168] PJM Filing to FERC in Docket No. ER11-3322-000 on April 7, 2011.

[169] DR performance is assessed on an aggregate basis for the provider's zonal portfolio. PJM explains that some of the over-performers are end-users that manage their super-peak loads and thus have low PLCs. They can provide additional reductions in non-super-peak hours, but not in the super-peak hours. Thus, they can over-perform (beyond their registered capacity) and cover for under-performers if events are only called outside of the super-peak hours.

interrupting a particular baseload process or turning on a backup generator. Such guaranteed load drop is valuable for RPM. If PJM's proposal is adopted, it will be important to fully preserve the GLD option in some manner.

Relatedly, some stakeholders have expressed concerns regarding the accuracy of PLC to measure each customer's contribution to the total capacity need. PLC is currently calculated by EDCs, usually based on the 5-CP method, which measures loads during the five highest zonal coincident peak hours during the summer before the delivery year. This method does not take into account the fact that capacity need arises outside the 5-CP hours, and some customers may find it relatively easy to avoid paying for any capacity by curtailing their load during just the super-peak hours that are likely to define the 5 CP. Therefore, we recommend that PJM ***consider working with the EDCs to refine their PLC methods***. Doing so would improve customers' incentive to more efficiently manage their load, and it would make PJM's proposed refinements to the GLD option less restrictive.

5. Future Directions

Future directions of RPM should include the incorporation of further resource types, in particular price responsive demand ("PRD") and advanced energy storage devices.

PJM recently presented its stakeholders with a proposal to integrate PRD into RPM. This proposal fits into a longer-term vision where PRD could play a more prominent role in electricity markets. In the long run, adding PRD will reduce the amount of generation capacity needed. By allowing LSEs to explicitly reduce their capacity obligations for expected PRD, capacity procurement costs also could be reduced. There have been competing PRD proposals, including one that PJM recently presented to its stakeholders.[170] The key (positive) elements of this proposal included PRD under supervisory control that commits to curtailments to a pre-determined level (Maximum Emergency Service Level) during PJM-declared emergencies, as well as a complementary scarcity pricing mechanism that would allow energy prices to rise above the current ($1,000/MWh) offer cap.[171] PJM and stakeholders should strive to complete the integration of PRD into RPM.

Another recent development has been the increased need for energy storage caused by the development of variable generation, especially wind. A range of advanced energy storage devices (such as, batteries, flywheels, thermal and compressed air energy storage, *etc.*) are currently under development. Although the primary driver behind the development of these devices is to provide additional ancillary services to balance the grid, these resources could also participate in RPM.

Energy storage devices have unique limitations that require a different methodology to calculate their capacity values. Storage devices may be able to provide two types of capacity products: (1) an annual product, for devices that can sustain their capacity value for at least 10 hours; and (2) a limited product for devices that can sustain their capacity value for at least 6 but less than 10

[170] PJM Staff Whitepaper, Price Responsive Demand, March 3, 2011.

[171] This is important because most loads have a higher reservation price, and low energy market offer caps would exclude them.

hours. We do not recommend adding any new capacity products for such a small category of potential capacity resources (compared to DR, for example) as that would make the RPM design more complex with questionable net benefits. Instead, to achieve the requirements of existing capacity products, multiple short-duration storage devices may need to be aggregated (*e.g.*, to reach 6 hours discharge capability) and mechanism would need to be developed to avoid recharging during dispatch periods.

6. Summary of Recommendations

We find that PJM's existing design mostly addresses identified stakeholder concerns, but we recommend that PJM and its stakeholders consider some refinements to further improve the efficiency of RPM and to ensure that all resources can perform as claimed.

With respect to the use of multiple capacity products to ***accommodate different resource types*** we recommend that PJM:

- 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.*, energy efficient air conditioning) from Annual to Extended Summer.

With respect to the ***assurances of performance***, we recommend the following enhancements for PJM's consideration:

- ***Tracking***: continue to rely on suppliers to manage potential deficiencies to avoid penalties; however consider requiring Curtail Service Providers ("CSPs") to periodically report their progress against planned milestones to increase visibility into progress and avoid surprises.
- ***Registration***: Introduce random audits of contracts and physical loads to verify zonal resource portfolio abilities to curtail as frequently and seasonally as represented (especially for Annual and Extended Summer), with appropriately punitive penalties to incent CSPs to represent accurately. These audits should be conducted before the start of the delivery year (when all "planned" resources have become actual resources involving end-users with contracts to curtail) or any time during the delivery year. This enhancement is our most important recommendation regarding DR even though little DR has yet cleared as Annual or Extended Summer resources.
- ***Testing***: conduct random tests and limit DR providers' ability to selectively choose the most favorable of (multiple) tests that. Tests should be called by PJM, and the duration of each test should be longer than one hour.

We recommend that PJM also consider slightly modifying its ***methodology for determining DR UCAP values***, in the following manner:

- ***FPR and DR Factor***: Eliminate both the FPR and the DR Factor for GLD-type DR, counting guaranteed load reductions at its full value (just like generation); for FSL-type DR, eliminate the DR Factor and maintain the FPR gross-up (or more).
- ***Derating capacity values for weak performance***: Derate future UCAP value of any resource (or a CSP portfolio) that under-performs during the most recent delivery years. Such derates already apply to generators as their average EFORd is lowered by past under-performance.

- ***Measurement and verification***: PJM should consider working with the EDCs to improve their methodologies for assigning PLCs, for example, by considering more hours than just the top five hours of the previous year.

Other recommendations:

- ***Price Responsive Demand ("PRD")***: PJM and its stakeholders should integrate PRD into RPM by finalizing the proposal that PJM has already proposed.

D. 2.5% Short-Term Resource Procurement Target

1. Background

Substantial concerns have been raised by several stakeholders about the 2.5% short-term resource procurement target (STRPT). This 2.5% "holdback" is a quantity of capacity held back from the 3-year forward procurement. The amount is subtracted from the BRA VRR curve and therefore not procured in the base auction. Instead, that capacity is procured over the following three years, with 0.5% procured in the first incremental auction two years prior to the delivery year, 0.5% in the second incremental auction one year prior to the delivery year, and 1.5% in the third incremental auction, just prior to the delivery year.[172] Starting with the BRA for the 2014/15 delivery year, the holdback has been subtracted not only from the VRR curve, but also from the Minimum Annual and Minimum Extended Summer resource requirements.[173] The result of this approach is that the STRPT quantity held back is Annual capacity, which means the resources procured in the incremental auctions for the 2014/15 delivery year will be primarily for Annual capacity.[174]

The STRPT was first implemented for the 2012/13 delivery year at the same time that Interruptible Load for Reliability (ILR) was eliminated and DR resources were first required to bid and clear through the centralized auctions. Prior to the incorporation of DR into RPM auctions, demand-side resources were allowed to participate as ILR, which could register just prior to the delivery year but still receive the BRA price.[175] To account for that, the base auctions included a "holdback" for an amount of capacity equal to the forecast quantity of ILR for the delivery year (an amount that would not actually be known until the delivery year). When the ILR mechanism was eliminated, the STRPT replaced the ILR-related holdback and was introduced primarily to accommodate demand-side resources that had never before had to make three-year forward commitments.[176] Eliminating ILR and implementing the STRPT to

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172 Other adjustments to reliability requirements and locational import limits are also reflected in these incremental auctions, including the incremental uncleared portion of the VRR curve and adjustments due to changes in load forecasts, see PJM (2011d), pp. 20-21.

173 See, for example, the calculation of the Extended Summer and Annual resource procurement targets as a function of the STRTP for the 2014/15 BRA, PJM (2011b).

174 However non-annual capacity may also be procured because of market participant buy bids, through adjustments to the reliability requirement, or through the incremental portion of the VRR curve that is included in these auctions.

175 See PJM (2011d), p. 29.

176 See PJM (2008f), pp. 39-41.

accommodate DR and other short-lead time resources was consistent with our 2008 recommendation.[177]

Members of the end-user and other supplier sectors stated that they support maintaining, or possibly increasing, the size of the STRPT. These stakeholders stressed that the three-year forward period creates significant risks for DR suppliers and other short-term resources. They note that the small size of the holdback, along with historically overstated load forecasts, have been artificially inflating BRA prices while causing IA prices to clear at much lower levels.

Generation owners, almost all transmission owners, and the Independent Market Monitor voiced their concerns over the 2.5% holdback and suggested that it should be eliminated. Their primary argument for eliminating the holdback is their concern that it artificially reduces demand in the BRA, thereby suppressing BRA prices below competitive levels. A supporting argument is that most of the supply in the BRA is under must-offer obligations and also mitigated in terms of their offer prices. The combination of must-offer obligations and mitigated offer prices prevents those participants from offering their capacity in the later incremental auctions, even if incremental auction prices are expected to exceed the BRA prices. In addition, some generation and transmission owners have argued that the 2.5% holdback is not needed to accommodate short lead-time resources, as evidenced by the large quantities of DR that have offered 3-years forward in the BRA.

The IMM has run BRA scenario simulations showing that, assuming the supply curve remains unchanged, increasing BRA demand by removing the 2.5% holdback would have resulted in price increases of $14 to $79/MW-day in the 2013/14 BRA, depending on location.[178] As we noted in Section V, one must exercise caution when interpreting these simulation results because they make the unrealistic assumption that the BRA supply curve would have been identical in the absence of the holdback.[179]

2. Discussion

The primary argument for eliminating the 2.5% holdback is that it will artificially suppress BRA prices by shifting demand from the 3-year forward auction to the later incremental auctions. In evaluating this argument, we looked primarily for two pieces of evidence. First, we looked for a pattern of incremental auction prices that were higher than BRA prices, which would indicate that shifting demand from the BRAs to the incremental auctions was indeed artificially suppressing BRA prices. Evidence is still limited as there have only been two incremental auctions conducted since the introduction of the 2.5% STRTP, but the results from these auctions show that incremental auction prices were generally below BRA prices. In the first incremental auction for 2012/13, RTO prices were identical to BRA prices, MAAC prices were $117/MW-day below BRA prices, and EMAAC prices were $14/MW-day above BRA prices. The increase

[177] See Pfeifenberger and Newell, *et al.* (2008), p. 101.

[178] See Monitoring Analytics (2010a), p. 31.

[179] We find it plausible to believe that, in the absence of the 2.5% holdback, some suppliers would have placed a higher value on clearing in the BRA given the lower likelihood of clearing in the IAs. In this case some suppliers may have offered into the BRA rather than waiting for the IAs or may have offered into the BRA at lower prices. For this reason, it is not clear how different the BRA supply curve might have been without a holdback.

in EMAAC prices was caused by the 1,455 MW increased local demand due to the delay in the Susquehanna-Roseland transmission line. The reduced prices in other LDAs are explained by reductions in demand due to decreased load forecast that exceeded the size of the holdback.[180] In the second incremental auction for 2012/13, prices were uniformly below BRA prices.[181] In other words, the opposite has been the case—BRA prices have been far above or persistently above incremental auction prices — although differences between the BRA and incremental auction prices are explained by factors other than the holdback.

Second, we examined the quantity of BRA supply that is either unmitigated in terms of its offer price or does not face a must-offer obligation. Unmitigated supply faces no offer price cap, like resources without a must-offer obligation, and can easily shift from the BRA to later incremental auctions if higher incremental auction prices are anticipated. These suppliers will therefore be able to rationally choose to sell into the auction with the highest expected prices, which will have an equilibrating effect on BRA and IA prices. In contrast, suppliers with must-offer obligations and offer price mitigation, do not have the flexibility to increase their offer BRA prices or shift their supplies to the incremental auctions. If the BRA clearing price is set within this mitigated portion of the BRA supply curve (without substantial quantities of unmitigated supply clearing inframarginally), this would artificially lower BRA prices.

To analyze this issue, we examined the quantity of cleared unmitigated BRA supply, as summarized in Figure 27 for the 2014/15 BRA.[182] The figure shows the cleared unmitigated supply for Limited, Extended Summer, and Annual resources and compares this quantity to the size of the STRTP, which is the same for each product type. For the Limited Summer product, the figure shows that the quantity of cleared unmitigated resources is 3.3 times larger than the holdback, indicating that the holdback has not suppressed BRA prices. The same pattern exists at the LDA level as well. If BRA prices were artificially suppressed, we would expect these unmitigated suppliers to shift their supply into subsequent incremental auctions, which would then have the effect of increasing BRA prices and decreasing incremental auction prices. We would expect supply shifts of this type to continue until BRA and IA prices were approximately equal in expectation.

In contrast to the Limited Summer product, however, the holdback for Extended Summer and Annual products was 2.6 and 2.0 times larger than the quantity of cleared, unmitigated supply for these products. The reason for these lower quantities relates to the fact that DR resources

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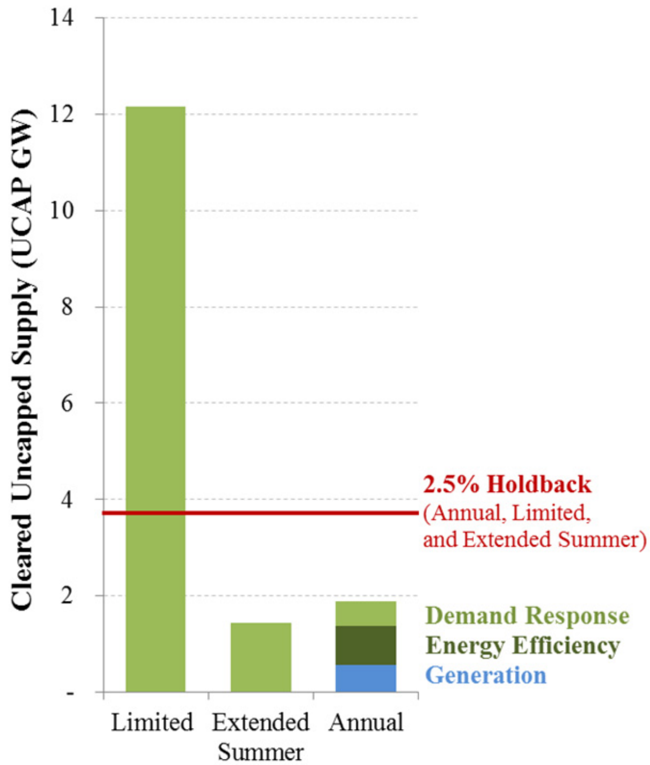
180 SWMAAC had an increase in demand of 409 MW due to increased load forecast and the STRTP. However, the LDA was unconstrained in the BRA and first IA, meaning that factors affecting MAAC prices were also the primary drivers of SWMAAC prices. See PJM (2009e, 2010g-h).

181 Note, however, that this is largely explained by demand reductions due to a decrease in load forecasts in every location, except PSEG-North and DPL-South. See PJM (2009e, 2011j).

182 We examined other BRAs as well, but found them less relevant to this analysis. Because such a large fraction of unmitigated supply consists of demand resources, we find only BRA data starting with 2013/14 to be informative as this was the first year that demand resources were unmitigated. Prior to 2013/14, "existing" demand resources were required to bid into the BRA at a mitigated price of zero. Examination of the 2013/14 BRA shows that the quantity of unmitigated cleared supply at 10,730 MW nevertheless greatly exceeded the 3,750 MW holdback. This result from the 2013/14 BRA is consistent with the evidence related to the limited product from the 2014/15 BRA, but does not inform the question of how the holdback interacts with Annual or Extended Summer resource requirements. PJM (2010a, 2011a).

account for most of the unmitigated supply, much of which cleared as Limited Summer supply. The much more modest amount of cleared unmitigated supply for Annual and Extended Summer products is problematic and indicates that the STRPT could possibly have lowered 2014/15 BRA prices for these products. Due to offer mitigation and must-offer obligations, suppliers would have had limited ability to shift their offers from the BRA to potentially higher-priced incremental auctions. However, this analysis is not conclusive since the cleared results already account for any shifting that may have occurred.

Figure 27
Cleared Unmitigated Supply in the 2014/15 BRA by Product Type



Sources and Notes: PJM (2011a-b).

This is a concern that should be addressed by concentrating the STRPT on Limited Summer products, which consists mostly of unmitigated short-term resources and in an amount that significantly exceeds the STRPT amount. Continuing to procure a portion of these resources closer to the delivery year will reduce the cost of providing these resources and, as we explained in our 2008 RPM Report, offer other benefits such as increasing liquidity in incremental auctions and providing PJM with more flexibility to adjust total capacity procurement in response to updated load forecasts.

3. Recommendations

Based on our analysis of stakeholder arguments and evidence to date related to the short-term resource procurement target, we make the following recommendations:

- ***Maintain the 2.5% STRPT for Total Resources* —** We recommend maintaining the short-term resource procurement target (STRPT) at its current level for the *total* system requirement.

- ***Eliminate STRPT for Extended Summer and all Annual Resources* —** We recommend eliminating the STRPT for the minimum amounts of Extended Summer and Annual resources to avoid distorting BRA prices for these products. We believe this modification will not substantially disadvantage short lead-time resources, because DR accounts for most short lead-time supplies, few of which have cleared as Annual or Extended Summer supplies. Eliminating STRPT for Annual Resources, which consist mostly of generation resources, will also add a safeguard to reduce the risk of resource adequacy challenges in the face of retirement pressures on existing coal plants from new EPA regulations. The full procurement of Annual Resources will reduce the risk that existing resources do not clear due to artificially suppressed BRA prices, which could lead to inefficient retirements of resources that may not be replaceable in the short term.

We also recommend that PJM continue to monitor that: (1) the amount of cleared unmitigated offers in each BRA and incremental auction exceeds the STRPT amount to avoid distorting auction prices as discussed above; (2) the quantity of supplies offered in the incremental auctions is sufficient to comfortably meet short-term procurement targets; and (3) prices and offer levels in incremental auctions are not substantially higher than in BRAs for reasons that appear unrelated to changes in market fundamentals.

E. Monitoring and Mitigation

1. Minimum Offer Price Rule

a. Background

In February of 2011, PJM filed with FERC a number of tariff modifications to update, simplify, and expand the applicability of its Minimum Offer Price Rule (MOPR).[183] PJM's filing was triggered partly by new long-term procurement efforts in New Jersey. The State of New Jersey had initiated a proceeding to solicit 2,000 MW of new in-state generation supply through long-term PPAs, whereby the winning projects would be required to bid into RPM as price takers. The PJM Power Providers Group ("P3") had subsequently filed a complaint stating that such out-of-market entry would artificially depress capacity prices, that the then-applicable MOPR would fail to prevent such entry or mitigate its effects, and that other changes were needed to the MOPR. PJM filed its MOPR proposal several days later, largely in agreement with P3, with a requested effective date in time for the Base Residual Auction earlier this year.

PJM's filing included the following major changes:

1. It eliminated the net short incentive test. This test was intended to narrow the application of MOPR only to entities with total capacity needs that exceeded the capacity that they owned, which would make them "net short" in the RPM market. Being net short creates an incentive to add capacity inefficiently in an effort to suppress the prices for the

[183] See PJM (2011h).

capacity they procured through RPM. This test would also have exempted generation suppliers such as those responding to New Jersey's solicitation because, unlike the ratepayers who would be contractually backing the capacity additions, the suppliers themselves would not be net short;

2. It eliminated the "impact test" that exempted any offers that reduce the auction clearing price by less than 20 to 30% (depending on the size of the LDA) since even a small amount of price suppression can harm competition;[184]
3. It modified the threshold and mitigation levels to be consistent with the Net CONE calculations used to determine the VRR curve (but the threshold was set at 90% of Net CONE for both combustion turbines and combined-cycle plants); and
4. It proposed to extend the amount of time that a planned resource would be subject to MOPR from one to three delivery years, counting only years when the unit would have cleared in RPM absent the MOPR.

PJM also proposed an exemption based on state mandates that address projected capacity shortfalls and several related changes.

The FERC's order, issued in April, 2011, accepted most of PJM's changes.[185] The order also rejected PJM's proposed three-year mitigation period and its proposal to review below-threshold sell offers through market participant filings under Section 206 of the Federal Power Act. PJM was required to submit a compliance filing specifying an offer review process conducted by the IMM first or, upon appeal, by PJM. Market participants would need to submit a Section 206 filing to FERC to request exemptions from the new rules, such as for reliability reasons). Since then, PJM has submitted its compliance filing and started working with stakeholders to develop the details of the offer review process.

In addition to accepting most of PJM's tariff changes, the order also clarified the Commission's views about the purpose and scope of the MOPR. For example, the MOPR Order rejected intervenor pleadings for exemptions for municipal utilities, cooperatives, and other entities that meet their customers' needs through resource planning.[186] It also rejected blanket exemptions for state initiatives lest captive customers pay above-market rates and wholesale market prices are depressed:

> … states are free to pursue their policy goals by financing new investments. We find only that such investments must submit bids into the capacity auction consistent with their competitive costs. Clarifying that the MOPR applies to new self-supply, however, does not prevent rate-based investments that are economic by market-based RPM standards from being designated as capacity resources. The MOPR, then, is both an appropriate and necessary mechanism to support market-driven investment in a way that does not expose captive customers to long-term investment risk.

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[184] See PJM (2011h), p. 18.

[185] See FERC (2011a).

[186] See FERC (2011a), pp. 191-197.

> Nor are we persuaded, as intervenors argue, that permitting new self-supply to be rejected at its preferred offer price is too harsh and too costly for ratepayers. First, as noted above, the FRR option is available for those load serving entities that want to secure capacity outside of the RPM market. Second, permitting new self-supply investment to compete as a price-taker in RPM impermissibly shifts the investment costs of self-supply to competitive supply by suppressing market clearing prices, and will create an environment in which only such self-supply investment will occur. Failure to subject new self-supply to the MOPR, that is, permitting new self-supply to participate in RPM as a price-taker, would significantly impede competition from all types of private investment and shift long-term investment risk from private investors to captive customers.[187]

These statements appear to establish a standard in which RPM-based procurement and Net CONE determinations will take precedence over capacity procured through bilateral contracts and resource planning efforts by vertically-integrated utilities.

b. Concerns

We agree that capacity markets need to be protected from manipulation by both sellers and buyers. Without the MOPR or an equivalent mechanism, market prices would be vulnerable to manipulation by buyers. If buyers with a significant net-short position in RPM were able to flood the market with excess capacity to depress prices, other suppliers' confidence in the market would undoubtedly collapse. This would likely lead to the undesirable outcome that new supply would be able to enter only through similar uncompetitive arrangements with buyers. This would also cause an increasing proportion of existing plants to retire uneconomically unless they, too, were able to obtain long-term contracts. There would no longer be a market where capacity resources of all types would compete. Expanding the original MOPR was necessary in order to close the key loophole that allowed net buyers, including states, to avoid mitigation by contracting bilaterally with an entity with a net-long capacity position.

However, we are concerned that the new MOPR will inadvertently interfere with self-supply offers from generating resources that are competitive and do not involve manipulation. We are particularly concerned that the MOPR will lead to over-mitigation that will undermine bilateral markets and RPM participation by entities, such as public power companies, that meet their customers' needs primarily through long-term contracts or other self-supply options.

The MOPR does not attempt to detect manipulative intent or incentives for manipulation. It is triggered whenever an RPM offer from new gas-fired generation falls below the administratively-determined benchmark level for that technology (*i.e.*, 90% of Net CONE for a CT or CC in level-nominal terms). However, there will be many legitimate reasons why an RPM bid could be below the Net CONE benchmark and should not be mitigated. In fact, the wide range of offer prices for new generation observed in RPM auctions over the last few years suggests the existence of a large range of cost structures, market outlooks, and bidding strategies.[188] The threshold of 90% of Net CONE is also imperfect because the discrepancy

[187] See FERC (2011a), pp. 194-195.

[188] As discussed in Section IV.C, we have observed offers for new generation at many different levels including zero, any fraction of Net CONE, and levels higher than Net CONE.

between the administratively-determined historical E&AS offset used to calculate Net CONE and the actual E&AS margins that market participants may anticipate to earn could easily exceed 10% of Net CONE.

The IMM and PJM have attempted to recognize these factors in the review process by determining offer floors for each resource, such as low project-specific costs (*e.g.*, due to an existing site with low-cost infrastructure needs), low financing costs, or additional competitive sources of revenue. However, there will also be legitimate other reasons for low bids that would be difficult to verify. For example, a competitive merchant developer might offer below the benchmark level if: (1) the developer anticipates rising energy and ancillary service margins (relative to 3-year historical E&AS offset used in the benchmark Net CONE calculation), thus reducing the amount of payment needed from the capacity market; (2) the developer anticipates rising equipment costs, which will tend to increase capacity prices over time, thereby reducing the amount of revenue needed in the first year of entry; or (3) the developer has already sunk a portion of the development costs, having started the project early in anticipation of different market conditions or due to a development schedule of more than three years. Such reasons might be difficult to recognize or validate in the IMM's offer review. Unfortunately, the inability to validate some legitimate factors may prevent the IMM from relying on them to determine offer floors. In addition, even if these factors would be considered in the review process, uncertainties about the review process itself will increase risks (*i.e.*, the risk of over-mitigating RPM offers) for many new resources and load-serving entities.

Over-mitigation would be particularly problematic for resources developed as self-supply or through bilateral contracts. In addition to the factors described above, self-supply and bilateral resources will rationally offer into RPM as a price taker (*i.e.*, offer at or near zero) if the development of the resource has already been committed. Such a project's development is not contingent on the auction outcome, but the project must clear to count toward the buyer's resource requirement or contractual obligations. Mitigating offers from such a generating unit is problematic because it might prevent the resource from clearing, the prospect of which could create a prohibitive risk for the resource owner, the load serving entity, or both. One might argue that a resource that does not clear in RPM auctions at its mitigated offer level is uneconomic and should not be developed. However, this argument ignores the factors described above (*e.g.*, Net CONE as an imperfect threshold), as well as the possibility that the lack of perfect foresight will result in some resources being planned and contracts being signed at prices that, contrary to initial expectations, turn out to be above or below market in some cases and some years. It would be unrealistic to expect market participants to be able to forecast uncertain annual capacity prices precisely enough to ensure clearing at MOPR-mitigated threshold prices and to avoid having to pay twice for capacity: —once for the bilaterally-contracted (but uncleared) resource and again for RPM capacity to replace the uncleared mitigated resource.

In fact, the inability of any buyer or seller to perfectly anticipate annual market prices is a principal reason to sign long-term contracts. RPM should facilitate such bilateral contracts, not prevent them, and also complement or facilitate resource planning by load-serving entities. RPM should inform entities' planning efforts and decision making through transparent auction prices and allow them to utilize auctions to efficiently balance their portfolios on a year-by-year basis.

We fear that the risk of not clearing self-supplied resources in the RPM auctions due to MOPR mitigation and uncertainties in the review process will create a barrier to bilateral contracting and other self-supply options. This will make it more difficult and costly to hedge capacity prices and will likely force many load serving entities that rely on self-supply to opt out of RPM through the FRR option. More widespread use of the FRR option would reduce market efficiency and increase costs because it places limits on selling into RPM, as discussed in our 2008 RPM Report.

c. Recommendations

The MOPR is needed to protect against buyers' manipulation of capacity prices through subsidized excess capacity. We believe, however, that the current rules are inefficiently structured, will inefficiently mitigate legitimate resource additions, and will discourage bilateral contracting and self-supply.

The objective should be to protect the wholesale capacity market from intentional manipulation, not from inadvertent effects that normal contracting and investment decisions can have on RPM prices, even if those investments and contracts turn out to be poor decisions. Further, it is important to recognize that over-mitigation can harm the market as much as under-mitigation. Any test and intervention thus needs to balance the risk of false positives (over-mitigation) against the risk of false negatives (under-mitigation).

We recognize that MOPR is already discussed extensively in other forums, including FERC dockets. However, given its importance to RPM performance, we offer a number of recommendations for consideration by PJM and stakeholders in these ongoing discussions. Our recommendations would exempt from mitigation self-supply options that are either (1) based on non-discriminatory competitive bilateral procurement processes; or (2) undertaken by entities or under circumstances without the incentive to suppress RPM auction prices. These recommendations differ from proposals the FERC has already considered in its Order. More specifically, we recommend that PJM and its stakeholders ***consider the following exemptions to MOPR mitigation***:

- Exempt resources that have won a competitive, non-discriminatory RFP that is open to both new and existing resources. Clearly, new generating units that can enter the market through such a bidding process are competitive and economic and should not be mitigated. They should be able to clear in the RPM auction as price takers, as the IMM has proposed.[189]

- Exempt self-supply resources that are offered into RPM by vertically-integrated LSEs if the resource is the result of a deliberative planning process by the LSE and the LSE is not substantially net short in RPM.

- Exempt a resource if the owner—and its contractual counterparty, if relevant—are not substantially net short in RPM and, thus, would not benefit from suppression of RPM capacity prices. To qualify for such an exemption would require a verification process, such as: (1) the resource owner would have to show that it is not net short; (2) the resource owner would have to disclose all contracts with counterparties; and (3) the

[189] See Monitoring Analytics (2011), pp. 5-6.

contractual counterparties would need to make available documentation that they are not substantially net short.

Implementing such exemptions would require PJM and stakeholders to determine an appropriate threshold of an LSE's acceptable net short position. For example, a MOPR exemption could be granted if the net short position is small enough such that the benefit of market price suppression obtained on the net short position would likely be less than the above-market subsidy implied by the contract price or the self-supplied assets' cost.

2. Default Offer Cap of Zero for Existing Generators

a. *Background and Concerns*

The default offer cap for existing generators, which are under a must-offer obligation, is \$0/MW-day.[190] To offer at a higher price, generators may submit data and documentation of their resource-specific costs based on either: (1) avoidable costs less projected net energy revenues; or (2) the documented opportunity costs of not exporting capacity into another market. An offer cap based on avoidable costs must be calculated assuming the unit will either mothball or retire if it fails to clear.[191] Alternately for generators in the unconstrained RTO and in an asset class deemed unlikely to be a price-setting resources, these units may opt to use a default ACR rate calculated and updated prior to each BRA.[192]

Some stakeholders have expressed the concern, and we agree, that a default offer cap of zero for existing generators is too low because it does not account for costs and risks of the forward capacity obligation, particularly considering their must-offer obligation. If a generator expects large enough operating margins in energy and ancillary services markets, then it would still prefer to operate rather than to mothball or retire even if it receives no capacity payment. However, the generator would not rationally choose to take on the obligations of an RPM commitment without at least some compensation. Fair and efficient compensation for this obligation may be small, but it will not be zero. At a minimum, it would reflect the risk of deficiency penalties and the costs associated with complying with the day-ahead must-offer obligation in the energy market.[193]

Deficiency penalty risks would be a function of the penalty rate of \$20/MW-day applicable at very low capacity prices[194] and a measure of uncertainty regarding a plant's UCAP value including EFORd uncertainty and unanticipated unit derates or retirement.[195] The costs of complying with the must-offer obligation would likely be small or zero for large generators that

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[190] See PJM (2011d), p. 64-65.

[191] See PJM (2011d), pp. 64-65; (2011q), Attachment DD, Sections 6.4, 6.7-8.

[192] See for example the 2014/15 ACR data at PJM (2011r); see also PJM (2011q), Attachment DD, Section 6.7.

[193] Explanations of penalty structures and the day-ahead must-offer requirement are available from PJM (2011d), p. 66 and Section 9.1.

[194] Deficiency penalties are the greater of \$20/MW-day and 20% of the capacity price; the \$20/MW-day applies when capacity prices are very low, which is the only case in which (low) non-zero offer caps are likely to matter.

[195] See PJM (2011d), Section 9.1.

intend to operate year-round in the energy and ancillary service markets in any case, but may be higher for small or high-cost generators with very low capacity factors who might otherwise opt to reduce costs by shutting the plant down during off-peak seasons. While calculating a likely low, near-zero offer cap may be an onerous process if done on a unit-by-unit basis, it seems that this could be done effectively on a class-average basis. Such a default ACR rate for units that will operate regardless of the energy price could be posted by the IMM along with the ACR rates for units that would otherwise mothball or retire.[196]

b. *Recommendations*

We understand that PJM and stakeholder have previously discussed this topic. However, based on the above considerations, we recommend that PJM and stakeholders reconsider developing an above-zero default offer cap for units that could otherwise operate in the energy and ancillary services markets even without a capacity payment.

- **Above-Zero Default Offer Cap for Existing Generators —** We recommend increasing the minimum offer cap so that no resources are required to offer at zero, but instead may offer at a level that includes the incremental cost of capacity supply obligations to a resource that would operate with or without any capacity payments. This minimum offer cap may be quite low, but would include an estimate of: (1) the risk of deficiency penalties; and (2) the costs of complying with the energy must offer requirement.

It is important to note that such a minimum offer cap for existing generators would not create a price floor for RPM auctions because generators would be free to bid below the offer cap.

F. NEPA and Alternatives for Extending Forward-Price Certainty

1. Background

The New Entry Price Adjustment ("NEPA") was originally included in RPM to mitigate the price impacts of lumpy resource additions in small LDAs. NEPA is intended to allow providers of new resources in LDAs to "lock in" prices for three years under certain special qualifying conditions indicating that the resource addition would severely reduce the LDA clearing price, thus making entry less likely. However, the price impact conditions for new entrants to qualify for NEPA are difficult to meet. Only a single resource has qualified for NEPA to date, while 29 new resources have requested (but not awarded) NEPA treatment.[197]

In its December 12, 2008 filing addressing many RPM issues, PJM cited our 2008 report and proposed to expand NEPA. PJM proposed to eliminate the stringent price impact test and make NEPA available to all new entrants in a modeled LDA.[198] It also proposed to expand the term of

[196] See for example PJM (2011r).

[197] Many units have requested NEPA treatment in multiple bids in different auctions; these resources are counted only one time in this number. From PJM (2011a).

[198] NEPA would be available to any new resource in "an LDA that has a separate VRR Curve, if the LDA clears with a locational price adder, or if the LDA would have had a locational price adder had the new entrant not cleared." See *PJM Interconnection, LLC*, Docket ER09-412-000, filed December 12, 2008, at pp. 53-55.

NEPA pricing from three to five delivery years, which it then proposed to increase to seven years in a subsequent settlement filing.[199] FERC issued an order on March 26, 2009 rejecting PJM's proposed expansion to NEPA, with the following explanation:

> The proposed relaxation of the pre-conditions and the extension of the lock-in period go beyond the intent of the original provision, intended only to address the issue of lumpy investments in a small LDA. PJM's proposal would further bifurcate capacity markets by giving new suppliers longer payments and assurances unavailable to existing suppliers providing the same service. Thus, it would result in further price discrimination between existing resources, including demand response, and new generation suppliers. We therefore reject the proposal to change the existing NEPA provisions.
>
> We also recognize that a longer commitment period may aid the developer in financing a project. However, as PJM notes, RPM was designed to provide long-term forward price signals and not necessarily long-term revenue assurance for developers, and we must therefore balance the benefits of the longer commitment period (to the extent it fosters new entry by making project financing easier or cheaper) against the possible uplift payments in excess of auction clearing prices that loads may have to bear due an extension of the NEPA term. In our view, no party has made the case that extending the NEPA term to five or seven years strikes a superior balance to the existing provisions.[200]

In a subsequent filing, PJM stated that NEPA did not provide assurance for qualified resources for even three years, since offers were subjected to having to clear the base auctions for the following two delivery years. PJM proposed modifications essentially guaranteeing that the amount of qualified capacity that cleared in the first year would also clear in the following two years. FERC accepted these revisions in an October 29, 2009 order.[201]

Since then, stakeholders have expressed increasing interest, both publicly and in our interviews, in expanding NEPA to support new investment. Many see expanding NEPA as a way to address the lack of multi-year forward-price certainty within RPM, the current lack of interest in long-term bilateral contracting, and the perceived effect this has on generation development. We discussed long-term contracting and issues extensively in Section III.C.

Recognizing stakeholder interest in NEPA, PJM requested in its February 2011 "MOPR" filing the need to establish a date certain for addressing NEPA in a future FERC filing. FERC set an October 1, 2011 filing date and PJM is currently undergoing a stakeholder process to address the issue. We hope our analysis will inform that process.

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[199] See *PJM* Interconnection*, LLC*, Docket ER05-1410-000 *et al.*, filed February 9, 2009, at pp. 20-21.

[200] See 126 FERC ¶ 61,275, Order Accepting Tariff Provisions in part, Rejecting Tariff Provisions in Part, Accepting Report, and Requiring Compliance Filings, Issued March 26, 2009, at P149-150.

[201] See 129 FERC ¶ 61,081, Order on Proposed Tariff Provisions, Issued October 29, 2009.

2. Analysis of Options for Extending Forward-Price Certainty

Driven by concerns about a lack of long-term contracting and capacity-price uncertainty, stakeholders have proposed several options for extending forward-price certainty. While each of these options would extend price certainty for market participants, some of them would also have problematic consequences. We analyze here the advantages and disadvantages of each of these proposed alternatives:

1. *Extending the RPM Forward Period* — Some generation and transmission owners proposed a five-year forward period, moving the BRA two years earlier relative to the delivery year.
2. *Expanding NEPA* — Some stakeholders argued for expanding NEPA by relaxing qualification criteria, offering the option to existing generation and generation outside the LDAs, and/or extending the price assurance period to five or ten years.
3. *Introducing Mandatory Long-Term Procurement by PJM* — PJM would procure a portion of capacity needs in annual auctions for delivery periods spanning multiple years.
4. *Voluntary Long-Term Auctions* — PJM would develop centralized, voluntary forward auctions for standardized multi-year capacity products. Alternatively, these products could be traded continuously through an over-the-counter trading platform.

As explained in more detail below, we recommend that PJM facilitate bilateral contracting through centralized, but voluntary, multi-year auctions or hedging products to increase longer-term liquidity and pricing transparency in the capacity market. This recommendation is consistent with PJM's existing proposal. Only if lack of long-term contracting can be shown to threaten system reliability should PJM consider implementing mandatory long-term procurement options. We do not recommend expanding NEPA as a generally-available multi-year pricing option.

a. Extending the RPM Forward Period

As we discussed in Section V, we recommended that PJM maintain the 3-year forward design of RPM. Increasing the forward period to four or five years would likely increase overall costs as it would increase risks to suppliers due to changing market conditions and permitting uncertainties. Probabilistic simulations with the Hobbs Model in our 2008 RPM Report similarly showed that a longer forward period would not offer additional benefits. Given the increase in commitment-related risks, we do not believe that extending the forward periods beyond three years would be a cost-effective option to provide increased long-term pricing certainty.

We reconfirm our 2008 recommendation to maintain the 3-year forward auction design. While increasing the forward procurement period would likely increase overall costs because of the increased commitment-related risks, we also find that the three-year forward procurement period offers significant advantages over shorter forward periods. First, as discussed in Section II.A.4, the BRA results from the first several auctions show that the supply curves were very steep when the forward period was less than three years. The flatter supply curves for the three-year forward auctions offer significant benefits in terms of mitigating price volatility and creating a more competitive market environment. The three-year out visibility of cleared and uncleared resources also provides a valuable indicator of likely retirements, which may prove to be critical in addressing challenges related to environmental compliance.

b. Expanding NEPA

As a mechanism to reduce the risk of investment in a volatile market, NEPA does not appear to provide an efficient solution. NEPA provides new resources with a multiple-year price based on an auction whose parameters and competing supply offers reflect single-year market fundamentals. This mismatch can be expected to distort the bidding behavior of candidate NEPA resources. Moreover, the current NEPA also excludes DR and existing resources—as FERC emphasized in its order rejecting PJM's proposal to expand NEPA.[202] A distortion of market prices and inefficient outcomes would be the likely result. For example, if prices in future auctions were anticipated to drop due to planned transmission, new NEPA-supported generation could clear at current auction prices and receive a high price for subsequent years despite the fact that long-term resources would not have been needed. The NEPA mechanism would not recognize if expanding DR or delaying the retirement of an existing generator could more efficiently meet the short-term need until the planned transmission project is in service. At the same time, suppliers bidding with the hope to lock in a multi-year price may bid below the level supported by market fundamentals in the current auction, thus depressing the annual auction price.

However, NEPA may still be helpful for mitigating the price impacts of adding large resources to small LDAs—the investment barrier NEPA was originally intended to address. Otherwise, adding a large unit to a small LDA can eliminate the LDA price premium in subsequent auctions (when the entire new resource is considered "existing"), especially if load growth is low relative to the size of the new unit. This effect of lumpy investments in small LDAs can deter developers from adding new generation at a minimally-efficient scale (*e.g.*, a new 2×1 7FA combined cycle plant) in locations where it is most valuable. NEPA mitigates this lumpiness problem by allowing the new entrant to continue being paid at the price at which it cleared initially. The mechanism could still distort annual prices as discussed in the prior paragraph, but it would continue to apply more narrowly. NEPA applies only in an LDA that has a substantial shortage and only to relatively large resources. As noted earlier, to date NEPA been applied only once.

c. Mandatory Long-Term Procurement by PJM

Due to the distortions in annual auction prices that an expanded NEPA would cause, as discussed above, we do not recommend expanding NEPA as a solution for the lack of long-term price stability offered by RPM. If long-term pricing certainty is needed within the RPM construct, a more efficient alternative to extend forward-price certainty would be for PJM to introduce long-term procurement for a portion of PJM resource needs. For example, PJM could procure each year 7% of capacity needs under 7-year contracts (*i.e.*, for delivery years 3 to 10 years in the future). Over time, this process would procure approximately half (49%) of all resource needs, with the other half being procured through the annual terms under the current BRA design. Developers would gain enough price certainty to finance their projects, and consumers would be less exposed to price volatility, due to the laddering of the long-term contracts over time.

However, implementing such a concept would require PJM to make important decisions about major long-term contract terms: (1) how much total capacity should be procured under such

[202] See 126 FERC ¶ 61,275, Order Accepting Tariff Provisions in part, Rejecting Tariff Provisions in Part, Accepting Report, and Requiring Compliance Filings, Issued March 26, 2009.

long-term contracts (*e.g.*, more or less than the 49% in the above example) and (2) what should be the contract term (*e.g.*, more or less than the 7 years in the above example). Procuring too much capacity under long-term commitments could significantly increase deficiency risks for suppliers, particularly suppliers of existing resources that could become unavailable over time. Because the added risk may offset some or all of the reduced financing risk for new plants or existing plants with major investment needs, procuring too much capacity through such long-term arrangements could increase total costs. Because prices and quantities are locked in, customers would also face an increased risk of being forced to pay for out-of-market resources. For these reasons, we believe decisions on how much capacity should be procured under long-term contracts and the determination of contract durations are best left to market participants. Market participants know their own risk profiles better than PJM, and they are free to enter contracts on their own terms bilaterally. Market participants will also be able to adjust contracting terms if market conditions and industry financing practices change over time.

We do not recommend that PJM expand the scope of RPM to procure capacity on a long-term basis at this point. As we discussed in Section III.C, it is not clear that a market failure currently exists that would need to be resolved through mandatory long-term contracting. Current market conditions do not support long-term contracts for new plants because new generation is not currently needed. If market failures preventing long-term contracting were to become evident in the future, PJM could consider introducing long-term procurement of capacity into the RPM design at that point. The signposts to look for would be: (1) generation investment lags even as market prices reach or exceed Net CONE; (2) structural problems related to default service procurement prevent LSEs from signing long-term contracts, and a review and revision of default service procurement is unlikely; and (3) it can be determined with sufficient confidence that longer-term contracts through RPM-based resource procurement will actually be needed to assure resource adequacy at reasonable costs.

As discussed in Section III.C, we believe that generation development and bilateral long-term contracting will increase as load grows and old generation retires. However, the MOPR design may need to be modified to avoid creating a barrier to bilateral contracting (as discussed in Section VI.E) and state default service procurement arrangements may have to be reformed, as discussed in Section III.C.

d. Voluntary Long-Term Auctions

At this point, we believe that PJM's best option to facilitate long-term contracting would to conduct *voluntary* long-term auctions. Compared to mandatory long-term procurement through RPM, this approach would leave long-term contracting decisions up to the suppliers and buyers, who best know their own risk preferences.

PJM's administration of a centralized, but voluntary, auction would also increase forward price transparency and liquidity to long-term contracting. Auction results would indicate the prices and quantities cleared, which would help market participants forecast and plan. Even when no capacity clears, PJM could report bid-ask spreads of uncleared capacity and other information that would also increase forward price transparency. A PJM-administered voluntary auction would also enhance liquidity by facilitating a forward market for capacity as a commodity, where suppliers and buyers would not need to be concerned about their counterparties' individual risks. As with all existing PJM auctions, PJM would take responsibility for specifying contract terms, validating the qualifications and creditworthiness of suppliers and buyers, and for backing up each counterparty (subject to penalties for defaulting parties).

Some of the market-design details that PJM and its stakeholders would have to develop include auction terms, qualification and credit requirements, LDA representation and other auction mechanics, market monitoring, and implications for the BRA.

Term: It would be necessary to define forward products, such as 3 years, 5 years, and/or 7 years forward, starting with the BRA delivery year or standardized single-year products for multiple years beyond the 3-year BRA horizon.

Qualification and credit requirements. Because the delivery period would encompass multiple years and extend further into the future than the BRA, the qualification and credit requirements would likely need to be more stringent.

Market monitoring. The voluntary nature of the auctions would likely eliminate the need to mitigate supplier market power. Suppliers would have to compete for the limited number of buy bids in the forward auction, against each other and against the heavily-mitigated BRA. However, there is still a danger that buyers could manipulate prices downward by introducing excess capacity at low prices.[203] It may still be necessary to apply MOPR, including the MOPR modifications we recommend in the prior section.

Auction mechanics: Presumably, the auction would produce a single clearing price for each LDA and RTO. Transmission constraints would probably not have to be modeled, although LSEs would have to consider likely BRA price differentials when deciding how much to bid for capacity in any particular location in the voluntary forward auctions. LDAs would ideally be consistent with the LDAs modeled in all BRAs conducted for delivery within the extended delivery period of the long-term product(s). When new LDAs are modeled, PJM would need rules to address long-term buyers' exposure to zonal price differentials. To facilitate such long-term commitments, PJM would need to make available forward views of key administrative parameters—for example, the 5- and 10-year outlooks for CETL that we recommended in Section VI.A.VI.A.1

Implications for BRAs: It would probably make sense to conduct the forward auctions prior to each BRA. The cleared long-term resources would then pass through the BRAs, with bilateral buyers offering their procured long-term resources as a price taker at the resource's physical location.

It may also be possible to increase forward price transparency through a continuously-clearing over-the-counter trading platform for standardized capacity products.

[203] For example, merely disallowing self-supply offers in the voluntary forward may not mitigate this threat since someone planning on offering capacity at a zero price could submit a buy bid of infinity and be sure of clearing both its sell offer and its buy bid.

3. Summary of Recommendations on NEPA and Forward Contracting

As discussed above, we offer the following recommendations:

- ***Avoid expanding NEPA.*** We do not recommend expanding NEPA as a means to provide price certainty that may promote new investment. Doing so would introduce inefficiencies and distortions by allowing some resources to be paid for multiple years based on a single-year auction. However, for the purposes of mitigating the adverse effects of lumpy investments in small LDAs, we recommend that PJM retain NEPA.
- ***Centralized, voluntary multi-year auctions.*** To facilitate long-term contracting and forward-price transparency, we recommend that PJM consider introducing voluntary long-term forward auctions, as described above. This recommendation complements recommendations in other sections that strive to reduce RPM price uncertainty by addressing the administrative factors that contribute to this uncertainty.
- ***No mandatory long-term procurement at this point.*** We cannot recommend introducing mandatory long-term procurement by PJM at this point. The need for such procurement is not yet clear, and it would be very difficult to determine the economically-efficient terms and amounts to procure under such mandatory long-term commitments. However, this issue can be revisited in the future if investment barriers (*e.g.*, structural barriers to long-term procurement by LSEs as default service providers) were to become evident and it can be determined with sufficient confidence that longer-term contracts through mandatory RPM-based resource procurement would be needed to assure resource adequacy at reasonable costs.

VII. CONCLUSIONS

Our analyses show that RPM is performing well. Despite concerns by some stakeholders, RPM has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements. Resource adequacy requirements have been met or exceeded in both the RTO and, during the last four BRAs, in all of the individual LDAs at capacity prices generally below the net cost of new entry (Net CONE). Without considering new RTO members and FRR entities not participating in RPM auctions, RPM has been successful in attracting and retaining 28.4 GW of committed gross additions, consisting of 11.8 GW (ICAP) of demand-side resources, 6.9 GW of increased imports or decreased exports, 4.8 GW of new generation, 4.1 GW of generation upgrades, and 0.8 GW of reactivations. Net additions were 13.1 GW, considering 5.0 GW of retirements, 2.7 GW of derates, and 7.5 GW of resources withdrawn from auctions by FRR entities and other excused resources.

Year-to-year capacity price changes have been consistent with market fundamentals, reflecting changes in the supply and demand for capacity, as well as refinements to market design and changes in administratively-determined parameters. RPM has reduced costs by fostering competition among all types of new and existing capacity, including demand-side resources. It has also facilitated decisions regarding the economic tradeoffs between investment in environmental retrofits on aging coal plants or their retirement.

Stakeholders have raised a number of key concerns. We find, however, that several major criticisms of RPM are contradicted by the evidence available to date—most notably the arguments that RPM prices are too high, that RPM does not support investment in new generation of the right types in the right places, or that RPM cannot maintain reliability in the face of environmental retirements. Stakeholders expressed particular concerns about the volatility and unpredictability of RPM prices. Some of the observed price changes are consistent with changes in market fundamentals, which necessarily must be reflected in prices for the market to be efficient. Others are caused by the one-time implementation of various improvements to the initial RPM design, such as modeling more LDAs or the elimination of ILR. These impacts on prices reflect a non-recurring one-time adjustment, which is not a concern going forward.

However, price uncertainty remains high due to non-transparent and possibly excessive fluctuations in modeled transmission limits and other administratively-defined parameters in RPM. We thus recommend a number of refinements to make the determination of transmission limits and administrative parameters more stable and transparent. To increase forward-price transparency and facilitate long-term contracting, we also support the development of voluntary auctions or an over-the-counter trading platform for long-term capacity products.

We have identified several performance risks stemming from the RPM design that should be addressed to ensure that resource adequacy will be met going forward. To address these concerns, our main recommendations include the implementation of six safeguards that would mitigate the identified performance risks. Specifically, we recommend:

- Calibrating the E&AS offset methodology to E&AS margins actually earned by generation plants similar to the reference technology.
- Increasing the price cap of the VRR curve to mitigate under-procurement risks.
- Modeling constrained LDAs more proactively for locations where significant amounts of plant retirements are likely.
- Maintaining the 2.5% overall Short-Term Resource Procurement Target for the total resource requirement, but eliminating the “holdback” for Annual and Extended Summer resources.
- Introducing audits of demand-side resources to confirm their contractual and physical ability to respond as often and seasonally as claimed.
- And finally, establishing exemptions to the Minimum Offer Price Rule (“MOPR”) to better support competitive entry through bilateral and self-supply arrangements.

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LIST OF ACRONYMS

ALM	Active Load Management
APIR	Avoidable Project Investment Rate
APPA	American Public Power Association
APS	Allegheny Power Systems
ATSI	American Transmission Systems, Inc. (a FirstEnergy subsidiary)
ATWACC	After-Tax Weighted-Average Cost Of Capital
BRA	Base Residual Auction
CC	Combined Cycle
CCM	Capacity Credit Market
CETL	Capacity Emergency Transfer Limits
CETO	Capacity Emergency Transfer Objective
CONE	Cost of New Entry
CP	Coincident Peak
CPI	Consumer Price Index
CSP	Curtailment Service Providers
CT	Combustion Turbine
DEOK	Duke Energy Ohio/Kentucky
DPL	Delmarva Power and Light
DR	Demand Response
E&AS	Energy and Ancillary Service
EDC	Electric Distribution Company
EE	Energy Efficiency
EFORd	Equivalent Demand Forced Outage Rate
ELLC	Effective Load Carrying Capability
EMAAC	Eastern Mid-Atlantic Area Council
EPA	Environmental Protection Agency

EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation and Maintenance
FPR	Forecast Pool Requirement
FRR	Fixed Resource Requirement
FSL	Firm Service Level
GHG	Greenhouse Gas
GLD	Guaranteed Load Drop
GSU	Generator Step-Up
GW	Gigawatt (= 1,000 MW)
HAP	Hazardous Air Pollutant
IA	Incremental Auction
ICAP	Installed Capacity
ICTR	Incremental Capacity Transfer Right
ILR	Interruptible Load for Reliability
IPSTF	Interconnection Process Senior Task Force
IMM	Independent Market Monitor
IRM	Installed Reserve Margin
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt Hours
LDA	Locational Deliverability Area
LOLE	Loss of Load Expectation
LSE	Load-Serving Entities
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MACT	Maximum Achievable Control Technology
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Megawatt Hours
NAAQS	National Ambient Air Quality Standards
NEPA	New Entry Pricing Adjustment
NRG	NRG Energy, Inc.

NSR	New Source Review
NUG	Non-Utility Owned Generator
NYISO	New York ISO
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFR	Owner-Furnished Equipment
OTC	Over the Counter
PATH	Potomac-Appalachian Transmission Highline
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, LLC
PLC	Peak Load Contribution
PPA	Power Purchase Agreement
PPM	Power Project Management
PRD	Price Responsive Demand
PSD	Prevention of Significant Deterioration
QTU	Qualifying Transmission Upgrade
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability-Must-Run
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
STRPT	Short-Term Resource Procurement Target
SWMAAC	Southwestern Mid-Atlantic Area Council
TO	Transmission Owner
UCAP	Unforced Capacity
VOLL	Value of Lost Load
VRR	Variable Resource Requirement