POTOMAC ECONOMICS

Assessment of the Buyer-Side Mitigation Exemption Test for the Berrians Facility

by:

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October 15, 2013

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I. INTRODUCTION AND SUMMARY

The NYISO's Market Administration and Control Area Services Tariff ("MST") requires that the Market Monitoring Unit ("MMU") prepare a report to be posted concurrently with the results of any buyer-side mitigation ("BSM") determinations.[1] This report provides our review of the BSM determination for the Berrians Project, which is being developed by NRG Energy, Inc. ("NRG"). The Berrians Project is a combined cycle project that would interconnect at the Consolidated Edison Company's ("ConEd") Astoria West 138 kV Substation in New York City.

The NYISO has conducted the Part A and Part B tests of the BSM determination for the Berrians Project (which consists of projects in Interconnection Queue positions #201 and #224) as part of the Class Year 2011 ("CY11") process.[2] The NYISO has determined that the Berrians Project is not exempt under either the Part A or Part B tests. Accordingly, the NYISO has calculated an Offer Floor for the Berrians Project at the lower of: (a) the Unit Net CONE ("UNC") of the Berrians Project and (b) the Default Net CONE ("DNC"), which is 75 percent of the Mitigation Net CONE ("MNC").[3]

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1 See *Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc.*, 139 FERC ¶ 61,244 (2012) at PP 130:

> [Regarding the request for] a written report by NYISO's MMU confirming whether NYISO's mitigation and exemption determinations and calculations were conducted in accordance with the terms of the Services Tariff, and, if not, identifying the flaws inherent in NYISO's approach, we direct the MMU to prepare a public report discussing its assessment of the buyer-side mitigation determinations.

Also see MST §23.4.5.7.7.

2 The Part A and Part B tests are set forth in MST §23.4.5.7.2. Details on the NYISO's application of these tests are provided in the *BUYER SIDE MITIGATION NARRATIVE AND NUMERICAL EXAMPLE* ("*BSM Numerical Example*"), September 3, 2013.

Terms not defined herein have the meaning set forth in the MST, and if not defined there, then as defined in the Open Access Transmission Tariff ("OATT"). The MST and OATT are collectively referred to as the "Tariff" in this report.

3 Default Net CONE (also referred to as the "Default Offer Floor") is described in the definition of Offer Floor (MST Section 23.2,1; Mitigation Net CONE is a term defined in the NYISO's August 12, 2010 Compliance Filing, resubmitted August 24, 2010, in Docket Nos. EL07-39, ER08-695, and ER10-2371).

Overall, we concur with the NYISO's determination that the Berrians Project should not receive an exemption. This report discusses key results and assumptions in the BSM exemption test for the Berrians Project. For each assumption, the report discusses how the outcome of the test was affected by the assumption, whether the assumption was in accordance with the MST, whether the assumption was generally reasonable and consistent with the purposes of the BSM measures. In discussing the reasonableness of the particular assumptions, we identify potential concerns that may justify changes in the BSM rules. We anticipate providing to the NYISO and its stakeholders a number of recommended changes to the BSM rules ("BSM Recommendations") to address the tariff concerns discussed in this report.

The following sections review key elements of the NYISO's BSM determination for the Berrians Project. Section II discusses issues that affect multiple components of the test. Section III discusses the Part A test in which the NYISO compares the forecasted ICAP price in the first year of the Mitigation Study Period ("MSP") to the DNC. Section IV evaluates the estimated Cost of New Entry ("CONE") for the Berrians Project, which is used in the Part B test. Section V evaluates the estimated net revenue from the NYISO's Energy and Ancillary Services markets, which is also used in the Part B test. Section VI discusses the Part B tests in which the NYISO compares the forecasted ICAP price during the three-year MSP to the Berrians Project's UNC. Section VII summarizes our overall conclusions and discusses issues that could be addressed in future BSM determinations.

II. FACTORS AFFECTING MULTIPLE COMPONENTS OF THE TESTS

This section of the report discusses key assumptions that affect multiple components of the BSM exemption test for the Berrians Project. Subsequent sections provide additional detail on how the assumptions identified in this section affect individual components of the BSM determination.

A. STARTING CAPABILITY PERIOD OF SUMMER 2014

The Starting Capability Period is the capability period in which the Berrians Project is assumed to begin operating and offering capacity for the purposes of the Mitigation Exemption Tests ("METs"). The Starting Capability Period is important because the timing of entry affects the load forecast and other assumptions that are used in the ICAP price forecasts and the net CONE values that are inputs to the Part A and Part B tests.[4] If the Starting Capability Period is significantly earlier than an Examined Facility would likely begin operating, it can depress the ICAP price forecasts and inflate the Unit Net CONE ("UNC"), thereby increasing the likelihood of mitigating an economic resource. The higher UNC may raise the resource's Offer Floor above its true net cost of entry.

The Tariff requires the NYISO to assume that Examined Facilities will be in service three years after the start of the Class Year, so the NYISO must assume that CY11 projects will be in service beginning in May 2014.[5] However, CY11 project owners did not learn their final interconnection costs until September 2013—less than a year before they are assumed to be operational for purposes of the METs. The BSM measures are intended to provide a developer with the exemption test results *before* it begins building a new facility, since a competitive supplier might not move forward with such a large investment if it was not reasonably certain to receive capacity market revenues. However, in order for the Berrians facility to begin operations by May 2014, construction would have had to begin long before it learned its interconnection

4 The effects of the Starting Capability Period on the Part A and Part B tests are discussed in Sections III.A.1 and III.A.1.

5 See MST §23.4.5.7.2.

costs or MET results. Hence, the Starting Capability Period is not well-aligned with when the Examined Facility would likely be operational.

Although the Starting Capability Period for the Berrians Project was determined in accordance with the NYISO Tariff, we recommend the NYISO consider modifying the Tariff so that the Starting Capability Period is better aligned with when the Examined Facilities would actually begin operating.[6] We will be recommending that NYISO evaluate alternatives for establishing a Starting Capability Period that corresponds more closely to the actual in service date for the units being tested.

B. Treatment of Property Taxes

In New York City, a substantial portion of the annual levelized cost of new entry depends on the forecasted property tax obligations of the new resource. The normal effective property tax rate for businesses in New York City is 4.63 percent, adding approximately $88/kW-year ICAP to the cost of new entry for a new peaking unit.[7] However, the currently-effective New York State Real Property Tax Law ("Tax Exemption") states that a new generating facility in New York City may receive a limited exemption if it is a peaking unit or if it runs for fewer than 18 hours per start.[8] New combined cycle units like the Berrians Project are generally expected to operate for days at a time due to their relatively low operating costs. However, the savings from the Tax Exemption far exceed the profits that a combined cycle unit would earn from operating for longer than 18 hours per start.

6 Recent revisions to the NYISO's OATT were made to encourage projects to move through future Class Year processes in a more timely manner (this will be fully effective for Class Years after Class Year 2012). (See *New York Independent System Operator, Inc.*, Proposed Tariff Revisions Regarding Interconnection Process Improvements, Docket No. ER13-588-000, delegated letter order April 1, 2013.) However, it is likely that the process will still take 12 to 18 months before a project receives a final BSM determination, so some additional changes are necessary for the Starting Capability Period to be well aligned with when an Examined Facility would begin operating.

7 Assumes an overnight investment cost of $1,899/kW from the 2014 Demand Curve Reset model (dated August 22, 2013).

8 The tax law states that the exemption applies to a generating unit that "…has an annual average operation, during the calendar year preceding the taxable status date, of less than eighteen hours following each start of the unit…" NYS Real Property Tax Law Subdivision 17 of section 489-aaaaaa (Ch. 28, L. 2011.)

The NYISO assumed in the BSM exemption test that the Berrians unit would cycle on and off as needed to satisfy the 18 hours per start provision so they can receive the Tax Exemption. This is reasonable because the increased start-up costs and reduced net revenues would be far out-weighed by the benefit of the lower property taxes.[9]

C. INCLUSION OF MOTHBALLED UNITS IN CAPACITY PRICE FORECAST

The BSM exemption test requires the NYISO to project capacity prices as much as six years into the future. NYISO has concluded that it is required to include 618 MW of mothballed capacity in its ICAP price forecasts for New York City.[10] The set of generators that is assumed to be in service is important because the more capacity that is assumed to be in service, the lower the projected capacity prices. Consequently, over-estimating the amount of in service capacity increases the likelihood of mitigating an economic project, while under-estimating the amount of in service capacity may lead to under-mitigation. The capacity price forecast is very sensitive to the amount of capacity that is assumed to be in service with a 100 MW adjustment in UCAP changing New York City ICAP prices by up to $14.05 per kW-year UCAP in both the Part A and Part B tests.[11] Hence, the inclusion of mothballed generation in the capacity price forecast has a sizable effect on the forecasted prices and the ultimate BSM determinations.

In some cases, it is realistic to assume that a mothballed unit with no significant equipment failures would re-enter the market if capacity prices rose to the levels that might induce new investment in generation. However, the requirement to do this in all cases will generally lead to unrealistically low capacity price forecasts in the Part A and Part B tests because:

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9 The effects of the Tax Exemption on the cost of new entry are discussed in Section IV.A.1, while the reduced net revenues that result from meeting the 18 hour per start criteria are discussed in Section V.C.2.

10 The definition of Expected Retirements in MST §23.4.5.7.3.2 does not include mothballed capacity.

11 The effects of including mothballed units in the Part A and Part B tests are discussed in Sections III.A.2 and III.A.2. The effect of mothballed units is reported in *NYC ICAP Forecast Inputs for Class Year 2011* (published July 17, 2013).

- Mothballed units may face significant costs to re-enter, particularly if this would require significant repairs or other capital expenditures; and

- Suppliers with large generation portfolios that include mothballed units may not have competitive incentives to re-enter the market, since this would lower the capacity prices for other units in the portfolio. There are currently no mitigation measures that would compel a supplier to return a mothballed unit to service if it were economic to do so.

The requirement to include mothballed units will have large effects on the METs given that suppliers may keep their units in a mothballed state for up to three years before being compelled to give up their CRIS rights or re-enter the market. Although the NYISO's inclusion of mothballed units in the capacity price forecasts was done in accordance with its Tariff, we believe there is a substantive deficiency in this methodology. The Commission recently acknowledged this problem and encouraged the NYISO to work with stakeholders to amend the BSM rules.[12] Our BSM Recommendations will include several potential reforms that NYISO and its stakeholders should evaluate to address this issue.

D. Inclusion of Units Relinquishing CRIS Rights in Capacity Price Forecast

As discussed in the previous sub-section, the set of units included in the capacity price forecast significantly affects the capacity price forecasts in both the Part A and Part B tests. Hence, it is important to consider how the overall results of the MET were affected by the inclusion of approximately 100 MW of capacity in the forecast that is expected to relinquish its bus positions and CRIS rights to the Berrians project and retire.[13, 14]

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12 See *New York Independent System Operator, Inc.*, 143 FERC ¶ 61,217 (2013) at P 111.

13 See *NRG Astoria Repowering, Response to Request for Information, The New York Energy Highway*, May 30, 2012. On page 4:

> Queue positions 201 and 224 total 250 MW interconnecting to the Astoria West 138kV substation. These positions presently utilize 100 MW of grandfathered interconnection rights from the existing NRG Astoria Westinghouse units. It is being studied as a Class Year 2011 project and is anticipated that the unit will be fully deliverable.

On page 17:

Although it is generally reasonable to assume in-service units will remain in service throughout the MSP, it is illogical to assume these Astoria GTs would sell capacity after the Berrians Project is in service.

The NYISO's inclusion of these Astoria GTs in the ICAP price forecasts was done in accordance with the Tariff, but we believe that rule changes should be considered so that more reasonable assumptions can be made in the future.[15] This issue could be addressed by the NYISO's Repowering/Replacement proposal, which would allow the BSM examination to consider when the Examined Facility would replace an existing facility.[16]

E. Effect of UDRs on Capacity Price Forecasts

The METs require the NYISO to estimate the effects on capacity prices of transmission lines that possess Unforced Deliverability Rights ("UDRs"). The assumptions regarding such transmission lines are important, since there is currently 1 GW of potential UDR capacity between PJM and New York City. The evaluation of potential UDR capacity is complicated by two factors:

1. Transmission lines possessing UDRs must obtain capacity from the neighboring market in order to sell capacity into New York City. They will not generally do this unless the New York City price is expected to be greater than the price in the neighboring market.
2. If the holder of rights to use the UDRs elects by the annual deadline not to use its UDRs to import capacity to New York City, the IRM Study Report will assume the line can provide emergency assistance. Consequently, the existence of the transmission line will

Queue positions #201 and #224 (a/k/a Berrians GT I and GT II) which would comprise one, 1-by-1 combined cycle unit that will connect to the Astoria West 138kV location. This unit will utilize the bus position of four existing NRG Astoria Westinghouse GTs of approximately 100 MW that will be demolished with the construction of this unit.

14 The effects of including these units in the Part A and Part B tests are discussed in Sections III.A.3 and III.A.3.

15 MST §23.4.5.7.3.2 deems that Expected Retirements be based on whether a Generator has already provided written notice to the New York Public Service Commission of its intent to retire.

16 See presentation *Proposed ICAP Buyer-Side Mitigation Modifications*, by Randy Wyatt and Dr. Nicole Bouchez, BIC Meeting, August 20, 2013.

reduce the Locational Minimum Installed Capacity Requirement ("LCR") for New York City.[17]

When conducting the MET for the Berrians Project, the NYISO assumed that transmission lines possessing UDRs would import capacity to New York City when capacity could be sold at a price that would compensate the line owner for the cost of obtaining capacity in the neighboring market.[18] This criterion was applied by Capability Year since the neighboring markets run annual rather than monthly capacity auctions. Depending on the amount of UDRs the NYISO assumed would be used to sell capacity into New York City, the NYISO adjusted the assumed LCR for New York City to reflect additional emergency assistance in a manner consistent with the IRM Study Report.

We find that these assumptions are reasonable and compliant with the NYISO Tariff. However, this highlights a shortcoming in the current BSM rules, which is that mitigation of uneconomic investment in transmission does not prevent it from affecting capacity prices because it can lower the IRM and LCR(s). Our BSM Recommendations will address this issue.

F. Capacity Offers from Mitigated Projects

The BSM exemption test requires the NYISO to estimate the effects on capacity prices of resources that have been mitigated under the BSM rules. An Offer Floor is imposed on such resources until the resource clears for 12 months, which do not have to be consecutive.[19] The assumptions regarding such resources are important, since two resources totaling over 1 GW of capacity have already been determined to not be exempt under the BSM rules.[20]

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17 The effects of the assumptions regarding UDR capacity in the Part A and Part B tests are discussed in Sections III.A.4 and III.A.4.

18 As discussed in *Assessment of the Buyer-Side Mitigation Exemption Test for the Hudson Transmission Partners Project*, the NYISO assumes that the cost of capacity in PJM's PSEG-North Local Delivery Area is equal to the clearing price in the Base Residual Auction in the closest year for which data is available.

19 The 12-month criterion is applied by output level, so if a 100 MW resources clears 60 MW for six months and 100 MW for six months, 60 MW of the resource's output would not be mitigated and 40 MW would still be subject to the Offer Floor. See *BSM Numerical Example*, Section 6.4.

20 The effects of the assumptions regarding mitigated capacity in the Part A and Part B tests are discussed in

The NYISO considered how the Offer Floor of a mitigated unit would evolve over time in the capacity price forecasts. This required the NYISO to forecast capacity prices during not only the MSP, but also during the months leading up to the MSP. Accordingly, if a mitigated unit was expected to sell capacity in the months prior to the MSP or during the initial portion of the MSP, those sales would be considered in the NYISO's assumptions regarding how much of the unit's capacity would be subject to the Offer Floor in subsequent portions of the MSP. The price level of the Offer Floor of a mitigated unit was adjusted annually for inflation, using the 1.7 percent inflation rate underlying the currently-effective demand curves. We find that NYISO's methodology in this regard was reasonable and compliant with the NYISO Tariff.

Sections III.A.4 and III.A.4.

III. PART A TEST

An exemption is granted in the Part A test if the price forecast for the first year of the MSP is higher than the DNC (which is equal to 75 percent of the net CONE of the demand curve unit).[21] The NYISO forecasted UCAP prices of $97.35/kW-year in the Part A test, which was lower than the DNC of $134.61/kW-year UCAP for the same period, so the Berrians Project did not pass the Part A test. This section evaluates the assumptions used to forecast prices and to compare the prices with the DNC.

A. IMPLICATIONS OF FACTORS IDENTIFIED IN SECTION II

This sub-section discusses how factors identified in Section II affected the outcomes of the Part A test. The conclusion of this section describes how these factors in combination likely affected the overall results of the test.

1. Starting Capability Period of Summer 2014

As discussed in Section II.A, the Starting Capability Period is important because the assumed timing of entry affects the load forecast and other assumptions that are used in the capacity price forecast and the DNC. Under the current Tariff, the Berrians Project is assumed to enter in Summer 2014, although a more reasonable assumption for its entry date would be Summer 2016. If the Starting Capability Period were pushed back to the more realistic date, an additional 3.75 percent (442 MW) of anticipated load growth and 3.4 percent escalation in the assumed ICAP demand curve would increase the price forecast by up to $63/kW-year UCAP. However, such an increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor as discussed in Part 4 of this sub-section.[22]

21 See *BSM Numerical Example*, Section 2.

22 This is because a higher capacity price might induce a UDR project to import additional capacity from an external control area. Likewise, a higher capacity price might allow additional capacity sales from a resource subject to an Offer Floor.

2. Inclusion of Mothballed Units in Capacity Price Forecast

As discussed in Section II.C, the NYISO assumed approximately 618 MW (summer capability) of mothballed capacity would be offered as price-takers when it developed the capacity price forecast. Although the Tariff requires this assumption, we believe the Tariff is flawed in this regard. Excluding this capacity would raise the price forecast by up to $90/kW-year UCAP. However, such an increase would be partly offset by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor as discussed in Part 4 of this sub-section.[22]

3. Inclusion of Units Relinquishing CRIS Rights in Capacity Price Forecast

The NYISO forecasted capacity prices assuming that approximately 100 MW of capacity that is anticipated to relinquish its CRIS rights to Berrians will still be participating in the capacity market as price takers. Section II.D explains that doing so was not logical because this capacity cannot coexist with Berrians. Excluding this capacity would raise the price forecast by up to $14/kW-year UCAP in the Part A test. However, such an increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor as discussed in Part 4 of this sub-section.[22] Furthermore, some units that are anticipated to relinquish CRIS rights are also mothballed, so this would reduce the joint impact of resolving these two issues.

4. Treatment of UDR Projects and Mitigated Resources in Capacity Price Forecast

The NYISO's treatment of UDR projects and mitigated resources in the price forecasts was based on the criteria discussed in Sections II.E and II.F. The estimated cost of PJM capacity for UDR projects was $82/kW-year in the Part A test.[23] Since the NYISO's capacity price forecast was $97.35/kW-year UCAP, the NYISO assumed UDR projects would use their UDRs to sell

[23] The cost of PJM capacity is based on a clearing price for the PS-North Local Delivery Area of $225/MW-day for the 2014/15 BRA. If the Starting Capability Period were changed to May 2016 as discussed in Part 1 of this sub-section, a slightly lower clearing price of $219/MW-day for the 2016/17 BRA would be used instead.

capacity to the extent they were not prevented from doing so by an Offer Floor. Mitigated UDR projects were assumed to offer capacity at the higher of their Offer Floor and the estimated cost of PJM capacity.[24] Mitigated generators were assumed to offer capacity at their Offer Floor.[25] UDR projects that were not forecasted to sell capacity were assumed to elect to be considered as emergency assistance in the LCR for New York City. Although it is not known how much the emergency assistance affects the New York City LCR, a 1 percent increase in the LCR would increase the price forecast by up to $17/kW-year UCAP.

If the assumptions discussed in Parts 1, 2, and 3 of this sub-section were modified, it would tend to increase the capacity price forecast. These modifications would be partly offset by increased sales from mitigated UDR projects and generators to the extent allowed by the Offer Floor imposed on the resource. The amount of any additional sales from UDR projects and/or generators is not reported here in order to maintain confidentiality regarding the levels of the Offer Floors imposed on individual resources. However, the combined impact of various changes in assumptions is provided at the conclusion of this section.

B. CONCLUSIONS – PART A TEST

The NYISO forecasted prices of $97.35/kW-year UCAP in the Part A test, which was lower than the DNC of $134.61/kW-month UCAP for the same period. Therefore, the Berrians Project did not pass the Part A test. We find that the Part A test was performed in accordance with the Tariff.

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24 An Offer Floor was imposed on HTP, which commenced operations in the 2013 Summer Capability Period. Although the level of HTP's Offer Floor is confidential, the Offer Floor was based on the lower of the UNC and the DNC calculated from the 2013/14 ICAP Demand Curve, and therefore, the Offer Floor imposed on HTP could be no higher than $131.94/kW-year UCAP for the 2013/14 Capability Year. Based on the 2013 Goldbook, HTP has a summer capability of 660 MW.

25 An Offer Floor was originally imposed on AEII in December 2012, the level of which is confidential. Since the Offer Floor was based on the lower of the UNC and the DNC escalated from the 2010/11 ICAP Demand Curve, the Offer Floor imposed on AEII could be no higher than $98.28/kW-year UCAP for the 2012/13 Capability Year. Based on the 2013 Goldbook, AEII has a summer capability of 542.2 MW.

We identify three issues (in sub-sections A.1, A.2, and A.3) with the Tariff that reduce the capacity price forecast to unrealistically low levels. However, if the Tariff had been revised to address these issues, the effect on the Part A test of the Berrians Project would have been partly offset by an increase in forecasted sales from resources that are UDR projects and/or subject to an Offer Floor (i.e., Linden VFT, AEII, and HTP). Overall, we estimate that if the three factors above were addressed, the price forecast could increase to more than $140/kW-year UCAP in the Part A test, so addressing the three issues might have caused the Berrians project to pass the Part A test.

IV. Cost of New Entry

The BSM exemption test requires the NYISO to estimate the annual levelized cost of new entry of the Examined Facility, which is used as an input to the Part B test. The developer of the Berrians Project provided cost information that was evaluated by the NYISO with the assistance of Sargent & Lundy. The NYISO made a number of key determinations regarding how the cost information should be reflected in the estimated CONE of the project. The NYISO excluded a small share of the Berrians Project's total project costs corresponding to various studies and legal and permitting costs that were deemed to be sunk for the purposes of the MET. This section evaluates several important assumptions that were used in the NYISO's CONE estimates.

A. Implications of Factors Identified in Section II

This sub-section briefly discusses how factors identified in Section II affected the estimated CONE of the Berrians Project.

1. Treatment of Tax Exemption

The NYISO assumed that the Berrians generator would be cycled in order to satisfy the requirements for the Tax Exemption. This exemption is anticipated to lower the levelized carrying charge rate ("LCC") of a typical combined cycle by 3.3 percent (measured as a percent of the present value of the total investment cost).[26, 27] Hence, if the total overnight investment cost of the Berrians project was $2,000/kW, this exemption would lower the annual levelized CONE by $66/kW-year ICAP.

26 The use of the LCC is described in *BSM Numerical Example*, Section 3.1.

27 The effect on a typical combined cycle unit is based on the model that was used by NERA in the 2013 Demand Curve reset process for a combined cycle unit in New York City, assuming a 30-year amortization.

B. Cost of Pre-Existing and/or Common Facilities

The MST requires the NYISO to estimate the CONE of an Examined Facility based on its "embedded" cost.[28] As a general matter, the use of this term in the Tariff for the Part B test is problematic because while it is a useful concept in a regulated rate context, its applicability in an economic evaluation of market-based investment is questionable.

The Berrians Project will be located at a site with older generators and where additional generators are anticipated in the future. So, the Berrians Project is likely to use pre-existing equipment on the site, to share equipment with other generators at the site, and to share equipment with generators that have not yet been built. To reasonably estimate the CONE of the Examined Facility, it is important to allocate costs appropriately across multiple generators at a single site. This sub-section evaluates the criteria used by the NYISO for allocating costs to the Berrians Project when the costs are related to pre-existing and/or common (i.e., shared) facilities.

1. Pre-Existing Non-Common Facilities

Pre-existing non-common facilities include equipment that was originally built for another generator that is no longer in use. The NYISO estimated the embedded cost of pre-existing non-common facilities at the Berrians site based on their book values.[29] We believe that using the book value was consistent with the requirement to use embedded costs, although it may have led the NYISO to under-estimate the true economic costs that are relevant in determining whether the Berrians Project is actually economic. This issue had a small effect on the overall results of the MET.

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28 See definition of Unit Net CONE in MST §23.2.1. The Commission cited the following definition of embedded cost in *Astoria Generating Company v. New York Independent System Operator, Inc.*, 140 FERC ¶ 61,189 (2012) from *Resource, An Encyclopedia of Utility Industry Terms*, (PG&E, January 1985, p. 147):

> [a]n historical cost, or a cost that was incurred in the past. The costs associated with financing and depreciating current plant are embedded costs, in that they have already been incurred and cannot be varied. The embedded cost of service includes the capital cost of existing capacity, including plants built years ago as well as the most recent capacity additions.

29 Investopedia defines book value of an asset as "the cost of an asset minus the accumulated depreciation."

Although the NYISO adhered to the requirements of the MST, changes to the Tariff for future METs could better estimate the cost of pre-existing non-common facilities, consistent with the fundamental purpose of the test, which is to estimate the economic cost of new entry. The true economic cost of a pre-existing non-common facility depends on the alternatives to using it for a new generator.[30] The true economic cost of such a facility is better reflected in the fair market value of the facility than in its book value, which can cause the UNC to be inappropriately high or low. Our BSM recommendations will include suggested changes to address this issue.

2. Pre-Existing Common Facilities

As a general matter, when a project is located at an existing plant that is owned by an incumbent generator, the project may take advantage of the economies of scale that come from using facilities that were purchased or constructed well before the project was conceived and that are still being used for other generators at the same site. For example, the new project may share labor costs, control room functions, interconnection facilities, and inventory capacity with other generators at the site. Such facilities are known as pre-existing common facilities.

To the extent that NRG plans to use pre-existing common facilities, the NYISO allocated costs from such facilities to the Berrians Project only to the extent that additional costs would be incurred to expand the capacity of the common facilities. Hypothetically, if an on-site storage facility would be expanded 50 percent at a cost of $500,000 to accommodate the needs of the new Berrians Project, only $500,000 would be included in the CONE estimate for the MET, even if the Berrians Project was expected to share some of the pre-existing storage capacity with other units at the site.[31] We believe the NYISO's assumptions with regard to pre-existing common

[30] In this context, one alternative to building a new generator that would begin operating in the Starting Capability Period would be building the same generator in a subsequent period.

[31] This is a hypothetical example for discussion purposes, since the actual cost information for the Berrians Project is confidential.

facilities were consistent with the Tariff and likely to produce CONE estimates that are consistent with the true economic cost of the new entry.[32]

3. New Facilities with Multiple Future Uses

As a general matter, when a new generator is built, the developer may install equipment that will be shared by the new generator and another future generator (or other activity) at the site. Such equipment is similar to the common facilities discussed in the previous sub-section, but this sub-section deals with facilities that are shared by the Examined Facility and a second generator that does not yet exist. For example, suppose $1 million is spent for a piece of equipment when an $800k piece of equipment would have been sufficient for the Examined Facility. If the more costly piece of equipment was installed so that a second generator could be installed later, it would not be appropriate to allocate the full $1 million to the Examined Facility. Instead, it would be appropriate to allocate $800k to the Examined Facility and $200k to the second new generator. Failing to allocate costs appropriately under such circumstances could lead to inaccurate results in current and future METs. We will address this issue on our BSM recommendations.

The NYISO incorporated 100 percent of the costs of facilities at the Berrians Project site that might have multiple future uses in the CONE estimate for the Berrians Project. Although we believe that the NYISO's treatment of such costs does not constitute a tariff violation, it would have been more accurate to allocate a portion of such costs to the Berrians Project and the remainder to the alternative future use. However, the total amount of such costs was small and did not substantially change the outcome of the MET.

32 However, this treatment of common facilities could create significant loop holes in future BSM exemption tests if it were applied to pre-existing common facilities that were originally built for a generator that had not been grandfathered under the BSM rules or passed the Part B test. This is because a developer could install much of the equipment necessary for a large uneconomic generator as part of a project to build a small generator (that was abandoned, mitigated, or passed under the Part A test). If the equipment was common to both facilities, the developer would claim the costs had been incurred for the purpose of the first project. In such cases, it would be appropriate to allocate the cost of such common equipment in accordance with the method described in Part 3 of this sub-section treating the second project as if it were built first.

4. Conclusions

In its evaluation of the costs of pre-existing and/or common facilities, the NYISO's assumptions were generally reasonable and were consistent with the Tariff. However, we identify two potential changes that could enhance the accuracy of the CONE estimates, but would not have substantially affected the outcome of the MET for the Berrians Project. We will be providing recommendations to address these issues to improve the accuracy of CONE estimates in future BSM determinations and to eliminate potential loop holes for developers of uneconomic generation.

C. Evaluation of Developer's Cost Estimates

Before the NYISO performs the MET for an Examined Facility, the developer provides detailed cost projections. This sub-section discusses the evaluation by the NYISO, with assistance from Sargent & Lundy, of cost information submitted by NRG for major components of the Berrians Project. The evaluation included requests for additional information and clarifying information.

1. EPC Cost Estimates – Scope & Schedule

The EPC cost estimate used in the Berrians Project evaluation was based primarily on an estimate that was obtained by NRG and provided to the NYISO, although it was adjusted by the NYISO with input from Sargent & Lundy. The estimate provided by NRG assumed a set of terms relating to the scope and schedule that were not fully consistent with the specifications of the Berrians Project. The inconsistencies had the effect of making the Berrians Project appear to have a lower CONE than if the EPC cost estimate was for a project with a scope more consistent with the Berrians Project as proposed in CY11. In future METs, we recommend adjusting the EPC estimate as necessary to ensure that it is consistent with the circumstances of the Examined Facility.

2. EPC Cost Estimates – Contingency Costs

NRG submitted an estimate of its contingency cost that was not substantiated. The NYISO, in consultation with Sargent & Lundy, determined that a different contingency cost was more reasonable. The NYISO revised the contingency value accordingly rather than use the value provided by NRG. We agree with the NYISO's decision to use the estimate of its consultants rather than use the estimate of the project developer.

3. Cost of Capital

The NYISO and its consultants estimated the weighted average cost of capital ("WACC") of the Berrians Project using the Capital Asset Pricing Model ("CAPM").[33] NRG submitted estimates of financing costs, but these were unsubstantiated, so the NYISO concluded they were less reliable than the costs derived using the CAPM method. We agree with the NYISO's decision to estimate these costs using the CAPM model rather than use the estimate provided by the project developer.

D. Conclusions – Cost of New Entry

We reviewed detailed information on the NYISO's estimate of the annual levelized CONE of the Berrians Project. We find that the NYISO's estimates were made in accordance with the Tariff, although we identify two areas where the NYISO's estimates could have been improved (in sub-sections B.3 and C.1). Ultimately, these improvements would not have changed the overall results of the MET for the Berrians Project.

We identify one issue (in sub-section B.1) with the Tariff that slightly reduced the estimated annual levelized CONE of the Berrians Project. Hence, we will be recommending the NYISO modify the Tariff to address this issue.

33 The WACC is used as the discount rate in the LCC calculation and to calculate interest during construction.

V. NET REVENUE

The forecasted net energy and ancillary services revenue is a key component of the Part B test, since a new project developer expects to recoup a large share of its investment from future energy and ancillary services revenues.[34] Estimating the net revenue of a new generator is a complex endeavor, requiring the use of models to estimate future LBMPs at which the new generator would sell its output.

We carefully reviewed the assumptions used by the NYISO in estimating the net revenues for the Berrians Project to determine whether they were reasonable and consistent with the Tariff. We find that the NYISO used assumptions that were generally reasonable and were tariff compliant. We also discuss potential improvements in the assumptions, but conclude that the results of the BSM exemption test for the Berrians Project would not have been affected by these improvements.

A. CRITERIA FOR MAKING ADJUSTMENTS TO THE NET REVENUE MODEL

While it is important to maintain consistency with the Demand Curve model – to ensure that the Part B test is consistent in its comparison between the Unit Net CONE and the capacity price forecast – it also is important to estimate net revenues as accurately as possible based on information available at the time of the MET.

As in previous final METs, the NYISO started with the net revenue model that was used to derive the currently-effective Demand Curves, and then the NYISO made several incremental adjustments that were suited to the MET of the Berrians Project.[35] The Commission has provided guidance regarding when it is appropriate to make adjustments to the net revenue model. For example, the Commission approved the NYISO's use of natural gas futures prices in

34 Net revenues are an input to the Unit Net CONE, which is directly used in the Part B test. See *BSM Numerical Example*, Section 3.1.

35 For example, previous METs adjusted net revenues to account for the fact that the Examined Facilities would be interconnected on the 345kV system in New York City. Likewise, they were adjusted to account for natural gas futures prices.

the net revenue model for METs even though historic natural gas prices had been used to establish the 2011/12-2013/14 Demand Curves because of the "differing objectives" of the two models.[36] On the other hand, the Commission has indicated that using different inflation adjustments for the Default Net CONE and ICAP price forecast in the Part A test is inappropriate because it would not provide an "apples to apples" comparison.[37] Hence, it is appropriate to make adjustments to the net revenue model when there is a strong rationale for distinguishing between the Examined Facility and the Demand Curve proxy unit.

In the evaluation of the Berrians project, the NYISO made adjustments to the net revenue model to address two types of issues:

- Factors that are relevant to the net revenues of the Berrians Project, but not the New York City proxy unit used to establish the currently-effective Demand Curve;[38] and
- Factors that were not modeled in the 2011/12-2013/14 Demand Curves, but that are significant for the Berrians Project.[39]

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36 This Commission Determination was made in response to the complaint that use of gas futures in a MET constituted an "apples to oranges" comparison. See *Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc.*, 139 FERC ¶ 61,244 (2012), PP. 108-109:

> [W]e agree with NYISO that the objectives underlying the calculation of Default and Unit net CONE differ and that these differing objectives justify using natural gas price forecasts from different sources in calculating net energy and ancillary service revenues in the mitigation test versus in the demand curve reset process…the objective underlying the demand curves is to provide a reasonable opportunity for an efficient new entrant to recover its costs over its lifetime, and that using historical natural gas prices is likely to provide an accurate estimate of average of net energy and ancillary service revenues on average over time…By contrast, [the Part B] test is focused on a shorter time period…We agree with NYISO that natural gas futures prices are likely to provide the more accurate forecast of future natural gas prices in the near term individual years than would historical natural gas prices.

37 See *Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc.*, 139 FERC ¶ 61,244 (2012), P 61:

> To provide an "apples to apples" comparison of the projected Default Offer Floor to projected demand curve prices during the Default Mitigation Study Period, the demand curve prices projected for the one-year Default Mitigation Study Period, likewise, should reflect the same adjustment for inflation.

38 This includes the adjustments that are discussed in sub-sections B.1, B.2, C.1, and C.2.

39 This includes the adjustments that are discussed in sub-sections B.3 and B.4.

The remainder of this section discusses the particular assumptions that were made by the NYISO.

B. LBMP ESTIMATION MODEL

The first step in estimating net revenues is estimating LBMPs the units would receive when it runs. This section discusses the key adjustments the NYISO made to its model for estimating LBMPs.

1. Use of Gas Futures Prices

The NYISO employed an adjustment in the econometric model that considered how differences between the gas prices that prevailed over the three-year history and the gas prices expected by the futures market would affect the net revenues of the Berrians Project. Similar adjustments were made in the Part B METs for AEII, Bayonne, and HTP, although a similar adjustment was not made to develop the 2011/12-2013/14 Demand Curves. This is because the historic gas prices were deemed to be an appropriate basis for estimating net revenues over the life of the investment, which is the purpose of the Demand Curve Reset. Alternatively, the natural gas futures prices are more appropriate for estimating net revenues over the near-term, three-year MSP, which is the purpose of the MET.[36] Hence, this adjustment was made to improve the accuracy of the estimated net revenues for the Berrians Project and we support the use of this adjustment.

2. Zonal-to-Nodal Price Adjustments

The NYISO applied a zonal-to-nodal price adjustment in the Berrians Project's MET to account for the fact that it would be interconnected at the Astoria West 138kV bus in New York City, since the location used to establish the 2011/12-2013/14 Demand Curves was the New York City zone (i.e., Zone J). The zonal-to-nodal price adjustment used for the Berrians Project MET was more precise than the adjustment used in prior METs in that zonal-to-nodal ratios were calculated and applied by month and by hour for the Berrians Project. This method is a significant improvement over the cruder method that was used to account for the location of the

Examined Facility in previous METs, although the objective of the adjustment was the same as in previous METs. We support the use of this refined method of adjustment.

3. Variations in Resource Mix and the NYC Local Capacity Requirement

The resource mix and the Local Capacity Requirement ("LCR") were relatively stable before the 2011/12-2013/14 Demand Curve Reset. Since then, however, variations in these factors have had major effects on the relationship between the reserve margin in New York City and forecasted LBMPs. The resource mix in New York City has changed considerably since 2010 due to the retirement and mothballing of 1.5 GW of older steam turbine capacity and the entry of 1.7 GW of newer transmission and generation resources. These changes have reduced LBMPs without significantly changing the reserve margin in New York City.[40]

The net revenue model developed for the accepted 2011/12-2013/14 Demand Curves does not account for changes in the resource mix that can fundamentally change the relationship between the reserve margin in New York City and the LBMPs. However, this issue was recognized and several changes to the net energy revenue model were made by the independent Demand Curve reset consultant to address it in the 2013 Demand Curve reset process.[41] The NYISO determined that implementing the same changes in the net revenue model to forecast net revenues in the Part B MET for the Berrians Project would improve the accuracy the MET and, thus, implemented these modeling improvements. We support these adjustments in the net revenue model, which are necessary to account for the changes in resource mix that occurred after the 2011/12-2013/14 Demand Curves were accepted.

The adjustments to the net revenue model also allow NYISO to recognize the effects of changes in the New York City LCR. The New York City LCR was 80 percent for a long period of time. It increased to 81 percent in 2011, to 83 percent in 2012, and to 86 percent in 2013. For

40 Mothballed and retired units include Poletti, Astoria 20, and Astoria 40. Newer resources include AEII, Bayonne, and HTP.

41 See the August 2, 2013 *Final Report of the Independent Study to Establish the Parameters of the ICAP Demand Curves for the New York Independent System Operator*, NERA Economic Consulting, p. 73-74.

purposes of the BSM examination, it is reasonable to assume that the LCR will remain at 86 percent for the remainder of the MSP.[42] Consequently, LBMPs are expected to be lower for a given planning reserve margin because the planning reserve margin falls as the LCR increases (assuming no change in real-time supply and demand). Because the improved net revenue model used for the Berrians's MET evaluation does not include the reserve margin as a key input for forecasting LBMPs, it is better able to accommodate changes in the New York City LCR.

4. Treatment of Mothballed Units and Units Relinquishing CRIS Rights

As discussed in Sections II.C and II.D, the Tariff requires the NYISO to forecast ICAP prices assuming that the capacity of mothballed units and units relinquishing CRIS rights will be sold in the ICAP market if they have not provided notice of retirement to the New York Public Service Commission ("PSC"), although this will lead to an under-estimate of ICAP prices. MST §23.4.5.7.2 requires the NYISO to forecast the "reasonably anticipated" net revenues in the Part B test, and the Tariff contains no explicit requirements related to the treatment of mothballed units in the net revenue forecast.[43] Nevertheless, the NYISO concluded that it should assume that mothballed units and those units relinquishing their CRIS rights that have not provided notice of retirement will be in-service for purposes of estimating net revenues.

The Tariff seems to require the NYISO to make a reasonable forecast of which units would be in-service based on the available information, and it does not include any specific assumptions with regard to the set of units included in the forecast, so we do not support the NYISO's inclusion of mothballed units and units that are expected to relinquish their CRIS rights in the net revenue forecast. Although we do not believe the NYISO's assumption violated the NYISO's Tariff, we believe a more accurate estimate could have been used. There is little factual support for assuming the mothballed units would return to service. Since the units are owned by large New York City suppliers and there are no mitigation measures that would ensure they reenter

42 Note, this assumes 86 percent but for changes in the LCR that might arise from resources that affect emergency import capability based on their election of whether or not to use their UDRs.

43 In contrast, MST §23.4.5.7.3.2 requires the NYISO to use specific assumptions in the ICAP price forecast.

when economic, it is unrealistic to treat them as in-service in the net revenue forecast. Moreover, it seems highly unlikely that if a unit were to relinquish its CRIS rights the unit would also still be economic to remain in-service. Because the ICAP price forecast and the net revenue forecast are used for entirely different purposes, there is a strong basis for using different assumptions in the two forecasts. The ICAP price forecasts are used in the Part A and Part B tests as the basis for evaluating the net CONE of the Examined Facility. The net revenue forecast is used in the Part B test and, importantly, in the Offer Floor if the Examined Facility does not receive an exemption. The Offer Floor of a mitigated project will play a key role in determining the project's actual sales if it ultimately moves forward. Hence, it is appropriate to use the most realistic possible assumptions in the net revenue model.

It should be noted that the adverse effects of these assumptions were substantially reduced by the NYISO's adjustment to the LBMP estimation model to account for changes in the resource mix (which is discussed in Part 3 of this sub-section). Because of the resource mix adjustment, the model is able to account for the high operating costs of the mothballed units, which limits their forecasted effect on LBMPs. If the resource mix adjustment had not been made, the treatment of mothballed units would have substantially depressed the forecasted LBMPs and associated net revenues. For this reason, we do not believe that the NYISO's assumptions related to mothballed units and units that are expected to relinquish their CRIS rights affected the overall outcome of the MET for the Berrians Project.

C. SCHEDULING MODEL

The second component of the net revenue model is the scheduling model, which forecasts how the Examined Facility will be scheduled based on the LBMPs estimated in the LBMP model. The NYISO made several adjustments to the scheduling model to account for differences between the Berrians Project and the peaking unit used to establish the 2011/12-2013/14 NYC Demand Curve.

1. Combined Cycle versus Peaking Technology

The Berrians Project is a combined cycle generator, while the NYC Demand Curve unit is a peaking unit, so the Berrians project is expected to have a lower heat rate than the Demand Curve unit. As a combined cycle generator, the Berrians Project has the capability to provide synchronous reserves, higher start-up costs, and a longer minimum run time than the Demand Curve peaking unit.

Since the scheduling model used to develop the accepted 2011/12-2013/14 Demand Curves was designed for a peaking unit, the NYISO made several enhancements to adapt the model for a combined cycle. First, a commitment model determines the optimal set of hours in which to run the unit for a 24-hour period based on DAM LBMPs and ancillary services prices, considering start-up costs, the actual down time of the unit, minimum run time, minimum down time, the cost of operation at the minimum generation level, and the incremental cost of operation. The commitment model also produces optimal DAM energy and ancillary services schedules based on the incremental operating costs and the minimum generation level of the Berrians Project.

Second, for hours when the unit is committed, the dispatch model optimizes output based on RT LBMPs and Ancillary Services prices, allowing the unit to earn additional profits from balancing purchases and sales. The model also considers the effects of gas balancing charges by the LDC, which reduce the incentives to make balancing purchases and sales after the last intraday nomination window.[44]

These enhancements to the scheduling model produce more reliable estimates of net revenues for a combined cycle generator. They also provide a framework for modeling the effects of the Tax Exemption, which is discussed in Part 2 of this sub-section.

44 Gas balancing charges are estimated based on *Con Edison PSC No. 9-Gas* (Leaf 300.2), which indicates that consuming more/less than the quantity of gas scheduled by 6 pm on a particular gas day results in a 67 percent increase 40 percent decrease in the effective price of gas for the amount of gas that is over/under-consumed.

2. Considering the Tax Exemption

As discussed in Section II.B, the Tax Exemption law provides that a new generating facility in New York City may receive a significant property tax exemption if it is a peaking unit or if it runs for fewer than 18 hours per start. A new generator like the Berrians Project would normally operate for days at a time due to its relatively low operating costs. However, a competitive supplier would adjust the operating profile of its generator if the savings from lower property taxes would offset the lost net revenues and higher costs from cycling the units more frequently.

The NYISO's commitment model considered that the Berrians Project would perceive: (i) an opportunity cost for each additional hour of operation after start-up, and (ii) a benefit from each additional start-up because each start-up would enable the unit to earn additional net revenues from operating for another 18 hours. Under optimal scheduling conditions, the benefit per start-up would be 18 times the opportunity cost per run-hour. So, the NYISO's commitment model determined the hours of commitment incorporating an opportunity cost per run-hour in the minimum generation offer of the unit and a benefit per start-up in the start-up offer (i.e., an offer reduction) of the unit. Based on a forecast of DAM LBMPs, the NYISO estimated the minimum generation offer increase and start-up cost offer reduction that would lead the Berrians Project to satisfy the target of 18 hours per start optimally.

We found this methodology to be a reasonable approximation of how a competitive supplier would optimize the use of the Berrians Project in order to obtain the Tax Exemption. Furthermore, the rules for setting reference levels would allow for the inclusion of appropriate adders to reflect marginal costs, which would allow the unit to reflect the opportunity cost appropriately in its energy offers and avoid mitigation.

D. CONCLUSIONS – NET REVENUE

We reviewed detailed information on the NYISO's estimate of the reasonably anticipated net revenues of the Berrians Project. We find that the NYISO's estimates were made in accordance with the Tariff, although we identify one area where the NYISO's estimates could have been improved (in sub-section B.4). Ultimately, this improvement would not have changed the overall results of the MET for the Berrians Project. The net revenues are used in the calculation of the Unit Net CONE, which is used in the Part B test as described in Section VI.

VI. PART B TEST

An exemption is granted in the Part B test if the average capacity price forecast over the three-year MSP is higher than the Unit Net CONE ("UNC") of the Examined Facility.[45] The NYISO forecasted UCAP prices of $123.86/kW-year in the Part B test, which was lower than the Unit Net CONE, so the Berrians Project did not pass the Part B test.[46] The Unit Net CONE is equal to the annualized levelized CONE of the project minus the net revenue earned from selling energy and ancillary services.[47] This section evaluates the assumptions used to forecast capacity prices and the overall result of the Part B test. We find that the NYISO conducted these tests in accordance with the Tariff. However, we identify several issues that did not substantially affect the final outcome of the test, but that should be addressed in future METs.

A. IMPLICATIONS OF FACTORS IDENTIFIED IN SECTION II

This sub-section briefly discusses how factors identified in Section II affected the outcomes of the Part B test. The conclusion of this section discusses how these factors in combination likely affected the overall results of the test.

1. Starting Capability Period of Summer 2014

As discussed in Section II.A, the Starting Capability Period is important because the assumed timing of entry affects the load forecast and other assumptions that are used in the capacity price forecast and the Unit Net CONE. Assuming the Berrians Project would actually enter three years from the Class Year, a more reasonable assumption for its entry date would be Summer 2016 rather than Summer 2014. So, if the Starting Capability Period were pushed back to the more realistic date, an additional 3.2 percent (384 MW) of anticipated load growth and 3.4

45 See *BSM Numerical Example*, Section 6.2.

46 The Unit Net CONE is not provided in this report because it is confidential.

47 The estimated annual levelized CONE for the Berrians Project is evaluated in Section IV, while the reasonably anticipated net revenues are evaluated in Section V.

percent escalation in the assumed ICAP demand curve would increase the price forecast by up to $55/kW-year UCAP (assuming no increase in sales). However, this increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor, which is discussed in Part 4 of this sub-section,[48] and from the Berrians Project, which is discussed in sub-section B.

2. Inclusion of Mothballed Units in the Capacity Price Forecast

As discussed in Section II.C, the NYISO complied with the Tariff when it forecasted capacity prices assuming mothballed resources would be price takers, but we believe there are substantive deficiencies with this methodology. Approximately 618 MW (summer capability) of mothballed capacity was included in the forecast. Excluding this capacity would raise the price forecast by up to $90/kW-year UCAP (assuming no increase in sales). However, this increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor, which is discussed in Part 4 of this sub-section,[48] and from the Berrians Project, which is discussed in sub-section B.

3. Inclusion of Units Relinquishing CRIS Rights in the Capacity Price Forecast

As discussed in Section II.D, approximately 100 MW of capacity is anticipated to relinquish its CRIS rights if the Berrians Project moves forward. Although the NYISO complied with the Tariff when it forecasted prices assuming that these units would be price takers, Section II.D explains that doing so was logically inconsistent with other test assumptions, since these units would be unable to coexist with the Berrians Project as evaluated in the MET. Excluding this capacity would raise the price forecast by up to $14/kW-year UCAP in the Part B test (assuming no increase in sales). However, this increase would be offset partly by higher forecasted sales from UDR projects and/or resources subject to an Offer Floor, which is discussed in Part 4 of this sub-section,[48] and from the Berrians Project, which is discussed in sub-section B. Some

48 This is because a higher capacity price might induce a UDR project to import additional capacity from an external control area. Likewise, a higher capacity price might allow additional capacity sales from a resource subject to an Offer Floor.

units that are expected to relinquish CRIS rights are also mothballed, so this reduces the joint impact of the two issues.

4. Treatment of UDR Projects and Mitigated Resources in the Capacity Price Forecast

The NYISO's treatment of UDR projects and mitigated resources in the price forecasts was based on the criteria discussed in Sections II.E and II.F. The estimated cost of PJM capacity is $74/kW-month in the Part B test.[49] Since the NYISO's capacity price forecast was $123.86/kW-year UCAP, the NYISO assumed UDR projects would use their UDRs to sell capacity to the extent they were not prevented from doing so by an Offer Floor. MW of capacity from UDR projects subject to an Offer Floor were assumed to offer capacity at the higher of their Offer Floor and the estimated cost of PJM capacity.[50] MW of capacity from generators subject to an Offer Floor were assumed to offer capacity at their Offer Floor.[51] UDR projects that were not forecasted to sell capacity were assumed to elect to be considered emergency assistance in the LCR for New York City. Although it is not known how much the emergency assistance affects the New York City LCR, a 1 percent increase in the LCR would increase the price forecast by up to $17/kW-year UCAP.

If the assumptions discussed in Parts 1, 2, and 3 of this sub-section were modified, it would tend to increase the capacity price forecast. These modifications would be partly offset by increased

49 The cost of PJM capacity is based on an average of clearing prices for the PS-North Local Delivery Area of $225/MW-day for the 2014/15 BRA, $167.46/MW-day for the 2015/16 BRA, and $219/MW-day for the 2016/17 BRA. If the Starting Capability Period were changed to May 2016 as discussed in Part 1 of this sub-section, a higher clearing price of $219/MW-day for the 2016/17 BRA would be used instead.

50 An Offer Floor was imposed on HTP, which commenced operations in the 2013 Summer Capability Period. Although the level of HTP's Offer Floor is confidential, the Offer Floor was based on the lower of the UNC and the DNC calculated from the 2013/14 ICAP Demand Curve, and therefore the Offer Floor imposed on HTP could be no higher than $131.94/kW-year UCAP for the 2013/14 Capability Year. Based on the 2013 Goldbook, HTP has a summer capability of 660 MW.

51 An Offer Floor was originally imposed on AEII in December 2012, the level of which is confidential. Since the Offer Floor was based on the lower of the UNC and the DNC escalated from the 2010/11 ICAP Demand Curve, the Offer Floor imposed on AEII could be no higher than $98.28/kW-year UCAP for the 2012/13 Capability Year. Based on the 2013 Goldbook, AEII has a summer capability of 542.2 MW.

sales from mitigated UDR projects and generators to the extent allowed by the Offer Floor imposed on the resource. The amount of any additional sales from UDR projects and/or generators is not reported here in order to maintain confidentiality regarding the level of the Offer Floor imposed on individual resources. However, the combined impact of various changes in assumptions is provided at the conclusion of this section.

B. Treatment of the Berrians Facility in Capacity Price Forecast

MST §23.4.5.7.3.2 states that each Examined Facility should be included in the capacity price forecast. This provision also states that "when the ISO is evaluating more than one Examined Facility concurrently…" the NYISO should calculate the capacity price forecast assuming that each Examined Facility is offered at its presumptive Offer Floor (i.e., the lower of its DNC or UNC).[52] This procedure is necessary for identifying which Examined Facility is most economic when market conditions are such that only one facility should be granted an exemption.

No other Examined Facility was tested in the MET with the Berrians Facility, but the NYISO applies the procedure that is prescribed for multiple Examined Facilities (i.e., that the Berrians Facility would be sold at the lower of its DNC or UNC). The Tariff is not explicit about what to assume when only one Examined Facility is being tested, but MST §23.4.5.7.3.2 implies that the NYISO should assume all of the capacity is sold from an Examined Facility when it is the only one being tested. Ultimately, this assumption did not affect the outcome of the Part B test for the Berrians Facility, but there are circumstances when this assumption could lead an Examined Facility to pass the Part B test inappropriately. Therefore, in future METs, we recommend the NYISO assume that all of the Examined Facility's capacity is sold when it is the only Examined Facility being tested. The effect of this assumption combined with other factors is discussed in the conclusions of this section.

52 This procedure is illustrated in *BSM Numerical Example*, Section 6.2.

C. Calculation of Summer and Winter DMNC Values

In the MET, the NYISO assumed that the amount of capacity that the Berrians Project would be able to sell would be limited by its CRIS rights and its summer and winter Demonstrated Maximum Net Capability ("DMNC") test values. The maximum capability of most thermal generators is affected by the ambient temperature, so DMNC values are temperature-adjusted. Depending on the particular characteristics of a generator, an increase in the ambient temperature from 85 to 90 degrees can reduce its summer capability by several percent, so the assumptions regarding ambient temperatures have significant effects on the capacity revenues earned by the generator.

Generators normally conduct a DMNC test before each Capability Period. The actual DMNC test value is converted to a temperature-adjusted value based on the actual ambient temperature during the test and the average temperature during the peak load hour of each of the last four same-season Capability Periods. This temperature adjustment is used so that the amount of capacity a generator sells reflects its estimated capability during seasonal peak load conditions.

The MET for the Berrians facility assumed an ambient temperature of 90 degrees and 64.3 percent relative humidity in the summer and 28 degrees and 61.7 percent relative humidity in the winter, since this was the best information available. These assumptions result in seasonal capability values that are reasonably accurate, but we recommend the NYISO instead adjust the summer and winter DMNC values based on the average temperature during the peak load hour over a substantial period of time (e.g., ten years) in future exemption tests. This would improve slightly the accuracy of the capability values used in the exemption test. It is unclear whether more accurate DMNC values for the Berrians Facility would have been higher or lower, but the overall effect on the UNC was likely very small.

D. Conclusions – Part B Test

The NYISO forecasted prices of $123.86/kW-year UCAP in the Part B test, which was lower than the UNC for the Berrians Project, so it did not pass the Part B test. Based on the current BSM rules, we identify one potential improvement that we believe would affect the calculation of the capacity price forecast and one potential improvement that would affect the calculation of UNC: [53]

1. Assuming the Berrians Facility would sell all of its capacity – This would lower the capacity price forecast as discussed in Sub-section B.
2. Using an EPC cost estimate based on circumstances more consistent with the Berrians Project as proposed – This would raise the estimated CONE and the UNC as discussed in Section IV.C.1.

Since the first improvement would lower the capacity price forecast and the second improvement would raise the UNC, adopting these improvements would not have affected the results of the Part B test. However, we find that the Part B test was performed in accordance with the Tariff.

We identify three significant issues (in sub-sections A.1, A.2, and A.3) with the Tariff that reduce the capacity price forecast to an unrealistically low level. [54] If these three issues could have been addressed in the Berrians MET, the effect on the Part B test would have been partly offset by increased sales from UDR resources and/or resources that are subject to an Offer Floor and from the Berrians Facility. Overall, if the three tariff issues above were addressed, the price forecast could increase to as much as $170/kW-year UCAP in the Part B test. It is unclear whether this price level, together with the two potential improvements described above, would have caused Berrians to pass the Part B test without additional information on the EPC costs of the Berrians Facility.

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[53] We also identify three potential improvements that would have had relatively small effects on the results of the Part B test. First, we recommend including in the estimated CONE less than 100 percent of the cost of equipment that will be used by multiple units (see Section IV.B.3), which would slightly reduce the UNC. Second, we recommend excluding mothballed units and units relinquishing their CRIS rights from the estimated net revenues (see Section V.B.4), which would slightly reduce the UNC. Third, we recommend using more precise estimates of the summer and winter DMNC values (see Section VI.C), although it is unclear what effect this would have on the Part B test for the Berrians Facility, if any.

[54] We also identify one tariff issue that had a small effect on the results of the Part B test. Specifically, the tariff requirement to use the embedded cost rather than the fair market value for certain equipment may lead to inaccurate estimates of the CONE (see Section IV.B.1) and the UNC of an Examined Facility.

VII. Conclusions and Recommendations

The Berrians Facility did not pass the Part A and Part B tests, so it is not exempt from an Offer Floor. If the Berrians Facility becomes operational, an Offer Floor will be imposed at the lower of the Default Net CONE and the Unit Net CONE.

We reviewed materials documenting the NYISOs evaluation of the cost of investment, the reasonably anticipated LBMPs and net revenues, and capacity price forecasts. We conclude that the results of the Part A and Part B tests were in accordance with the requirements of the Tariff. However, we recommend several improvements to the assumptions used by the NYISO in future buyer-side mitigation evaluations. As discussed in Sections III.B and VI.D, the outcomes of the Part A and Part B tests for the Berrians Facility would not have been altered by the proposed improvements. The proposed improvements are summarized in the table below.

We also identify several issues with the Tariff that undermine the accuracy of the capacity price forecast and the Unit Net CONE. If these issues could have been addressed in the MET for the Berrians Facility, it is possible that the facility would have received an exemption (as discussed in Sections III.B and VI.D). In addition, these issues may have significant impacts on the results of future METs. We will be providing specific recommendations to address these issues in a subsequent BSM Recommendations report.

The following table summarizes the issues for which we identified a potential improvement in an assumption or an issue with the test that could be addressed by a tariff change. The second column indicates where each issue is discussed in the report. The third column indicates with an "I" where we recommend an improvement to the assumption used by the NYISO. The third column indicates with a "T" where we expect to recommend modifying the Tariff in the BSM Recommendations report.

Table 1: Summary of Recommended Enhancements to BSM Evaluation

Part A & Part B Test Related Issues:	**Section:**	**Rec:**
Starting Capability Period of Summer 2014	II.A, (In Part A test: III.A.1, In Part B test: VI.A.1)	T
Inclusion of Mothballed Units in Capacity Price Forecast	II.C (In Part A test: III.A.2, In Part B test: VI.A.2)	T
Inclusion of Units Relinquishing CRIS Rights in the Capacity Price Forecast	II.D (In Part A test: III.A.3, In Part B test: VI.A.3)	T
Part B Test – Cost of New Entry:		
Cost of Pre-Existing Non-Common Facilities	IV.B.1	T
Cost of Facilities with Multiple Uses	IV.B.3	I
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Treatment of Berrians Facility	VI.B	I
Calculation of Summer and Winter DMNC Values	VI.C	I