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Documentation Requirements for Unit Specific Market Seller Offer Caps

The request for a unit specific market seller offer cap (MSOC) should include the following documentation, as applicable.

1. Data and Documentation Submission
   a. A completed ACR Template should be submitted in MIRA by uploading it to the RPM/ACR module. The Avoidable Cost Rate (ACR) Template is available on the Monitoring Analytics website, Tools page.
   b. All supporting documentation should be submitted in MIRA by creating an RPM Offer Cap Documentation request and uploading the files.
2. Avoidable Cost Rate Data
   a. Time Period – The ACR data must be based on the 12 months preceding the month in which the data must be provided. If cost data are not available for the 12 months preceding the month in which the data was due, provide an explanation of and basis for the estimate in accordance with OATT Attachment DD § 6.7(d).
   b. Escalation Factor – An escalation factor equal to the 10 year average Handy Whitman index may be applied to account for inflation between the submission of the sell offer and the start of the relevant delivery year. See the ACR Escalation Guidelines available on the Monitoring Analytics website, Tools page.
   c. Avoidable Costs – Avoidable costs are the costs a generation owner would not incur if the generating unit did not operate in the delivery year. Avoidable costs do not include any such costs that are recoverable in a unit's energy offer. Avoidable percent is, for any category of costs, the ratio of the avoidable part of the cost to the total costs. Please explain, in writing, the basis for classifying each expense category as avoidable.
   d. Supporting Documentation for ACR Expenses
      i. Documentation includes internal accounting and financial reports.
      ii. Please provide a level of detail showing why the underlying expenses for the ACR line items are not includable in the cost based energy market offer in compliance with the FERC Order in Docket Nos. ER19-210-001, EL19-8-000, and EL19-8-001. For example, please provide documentation with a level of detail showing that the labor expenses include only straight time labor; that the expenses do not include consumable materials attributable to the production of electricity; and that the expenses do not include repair, replacement, or major maintenance directly related to electric production.
      iii. Demonstrate how the submitted ACR expenses in the ACR Template are reconciled with the values in the supporting documentation.

3. Avoidable Project Investment Recovery (APIR)
   a. Capital Recovery Factors (CRFs)
      i. Standard Age Based CRFs – For the standard aged based CRFs, eligibility is based on the age of the plant from the start of commercial operation through the relevant delivery year. Generators can choose to lengthen their CRF recovery by choosing a CRF of the next shortest interval. For example, a 15 year old plant could choose the CRF of a 10 year old plant.
      ii. Mandatory CapEx
         1. Eligibility – The Mandatory CapEx is an option for a resource that must make a project investment to comply with a governmental requirement that would otherwise materially impact operating levels during the delivery year, where such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.
         2. Election Timing – A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation.
         3. Sell Offer Price Restrictions – A sell offer submitted using the Mandatory CapEx option may not exceed 0.9 times the applicable net CONE in UCAP terms.
      iii. 40 Plus Alternative

         1. Eligibility – The 40 Plus Alternative CRF is available for a resource that is a gas or oil fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant RPM auction (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Tariff, Part V. Generation capacity resources electing the 40 Plus Alternative CRF shall be treated as at risk generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as at risk at the end of the one year amortization period.
         2. Election Timing – A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than 6 months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable. The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information.

3. Sell Offer Price Restrictions – A sell offer submitted using the 40 Plus Alternative CRF may not exceed the applicable net CONE in UCAP terms.

iv. Election – The CRF interval election is a one time election that cannot be changed during the recovery period.

v. Recovery Schedule – The remaining life of plant in the CRF table defines the maximum number of years in which a project may be included in APIR, and the beginning of the recovery period is the first delivery year after the expected completion date. For example, a project with an expected completion date of May 31, 2023, and a CRF of 25 Plus may include the project in APIR for the 2023/2024 through 2027/2028 delivery years.

b. For each capital project, provide a complete project description and purpose of the investment, including detailed information concerning the governmental requirement, if applicable. Please provide a level of detail showing why the APIR projects are not includable in the cost based energy market offer. For example, please provide documentation with a level of detail showing that the costs do not include repair, replacement, or major maintenance directly related to electric production.

c. For each capital project, specify the timing of the project completion and status. Based on CRFs other than the Mandatory CapEx, projects are includable in APIR if the expected completion date is prior to June 1 of the relevant delivery year. For the Mandatory CapEx option, projects are includable in APIR if the expected completion date is prior to the end of the relevant delivery year.

d. Evidence of Corporate Commitment. An SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment must be provided.

e. Documentation for Project Costs

i. For historic projects that are in service, this includes internal accounting and financial reports, project cost closeout reports or other equivalent documentation that includes the final cost of the project.

ii. For future projects, this includes an engineering evaluation of cost, contractor and vendor quotes, internal assessment, documented costs for similar past projects at other like technology units, or evidence from the company's capital approval process.

iii. Demonstrate how the submitted project costs in the ACR Template are reconciled with the values in the supporting documentation.

4. Capacity Performance Quantifiable Risk (CPQR)

a. Method Used to Evaluate Risk. Please provide a detailed description of the method used to calculate the submitted CPQR values and whether it is a deterministic method, probabilistic method, or some other method.

b. Deterministic Method

i. Provide the calculation in a spreadsheet, with all the inputs and assumptions for all the variables used to calculate the CPQR.

ii. For the inputs used that relate to unit performance, PAH, and balancing ratios, please provide any supporting documentation and include any analysis of historical data to support the assumed values.

c. Probabilistic Method

   i. Describe the sources of the risks for each unit, how they are modeled, any dependent and independent variables in the models.
   ii. Please specify the temporal granularity of the model. For example, hourly, weekly, monthly.
   iii. Please specify if empirical distributions are used for each variable, or if other distributions are assumed.
   iv. Please describe the historical data used to model the independent variables, and any modifications to the historical data based on forecasts.
   v. Please provide the frequency distribution tables and distribution curves for the independent variable data used as inputs to the CPQR calculation.
   vi. Please provide the frequency distribution tables and distribution curves for the projected output variables.
   vii. Please specify how the output of the model is used to calculate the CP non-performance charges and CP bonus payments.
   viii. Please specify the number of hours each unit is projected to be subject to penalties, and the number of hours each unit is projected to earn bonuses.

d. Officer Certification. An officer certification in accordance with PJM OATT Attachment DD § 6.8(a) must be provided asserting that the modeling and valuation of the CPQR was developed in accord with such actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business.

5. Net Revenues

   a. Identify all revenue sources (exclusive of any State Subsidies) or revenue guaranteed which may include any long-term power supply contracts; bilateral agreements; tolling agreements; or tariffs on file with state or federal regulatory agencies. Provide supporting documentation.

      i. Projected net energy and ancillary services revenues
      ii. Bilateral revenues and costs
      iii. Reactive capability revenues. Please provide the applicable FERC docket number.
      iv. Production tax credits (in lieu of investment tax credits)
      v. Revenues from the sale of renewable energy credits (RECs) for purposes other than meeting state mandated standards or state sponsored programs. Please provide the associated contract(s). The documentation must show that the buyer is not permitted to use the RECs to satisfy state renewable portfolio standards.

   b. Projected net energy and ancillary services (E&AS) revenues. MMU calculated projected net E&AS revenues or capacity market seller's own projected net E&AS may be used. If using own projected net E&AS, a well defined forward looking dispatch model must be used, designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must use publicly available forward prices for electricity and fuel in the PJM Region and include prices at the generator bus. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data and be clearly documented. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. Supporting documentation for this includes the following:

i. Documented estimates of future energy and fuel prices at the generator bus
ii. Variable operation and maintenance (VOM) expenses, consistent with PJM Manual 15
iii. Energy demand
iv. Emissions allowance prices
v. Expected environmental or energy policies that affect the seller's forecast of electricity prices in the relevant region
vi. Short run marginal costs such as variable water and sewer, lubricants and chemical expenses for water treatment and environmental control systems
vii. Plant performance and capability information including:

    1. Plant net heat rate and net capacity from 10 °F to 100 °F in 10 degree increments
    2. Start-up times and costs including fuel consumed, power consumed and produced, and emissions produced
    3. Forced outage rate
    4. Planned outage schedules
    5. Maintenance cycles
    6. Fuel costs, maintenance adders and operating costs, consistent with Operating Agreement, Schedule 2
    7. Expected capacity factor and output profile provided by a third party
    8. Ancillary service capabilities

c. Power Purchase Agreement (PPA) based net revenues. Please provide the PPA which should demonstrate that the agreement is an arm's length transaction. If REC revenues are included, the documentation must show that the buyer is not permitted to use the RECs to satisfy state renewable portfolio standards.

6. Opportunity Cost Based Offer Caps
    a. An opportunity cost based offer cap is the documented price available to an existing generation resource in a market external to PJM.
        i. A complete calculation of the requested opportunity cost based offer cap, accounting for the cost of transmission
        ii. Documentation for the projected price in the external capacity market
        iii. Detailed explanation why the submitted value represents the expected market value of the resource's capacity in the external capacity market for the relevant delivery year
        iv. Evidence of firm transmission
    b. Export and Import Capability Limits. If the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external

markets to import capacity in such year, opportunity cost based offer caps will be accepted starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of PJM's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost based offer cap is not accepted, an ACR based offer cap will be applicable.

7. In addition to the identified supporting documentation, the Capacity Market Seller shall provide any additional information requested by the MMU to evaluate the proposed market seller offer cap.